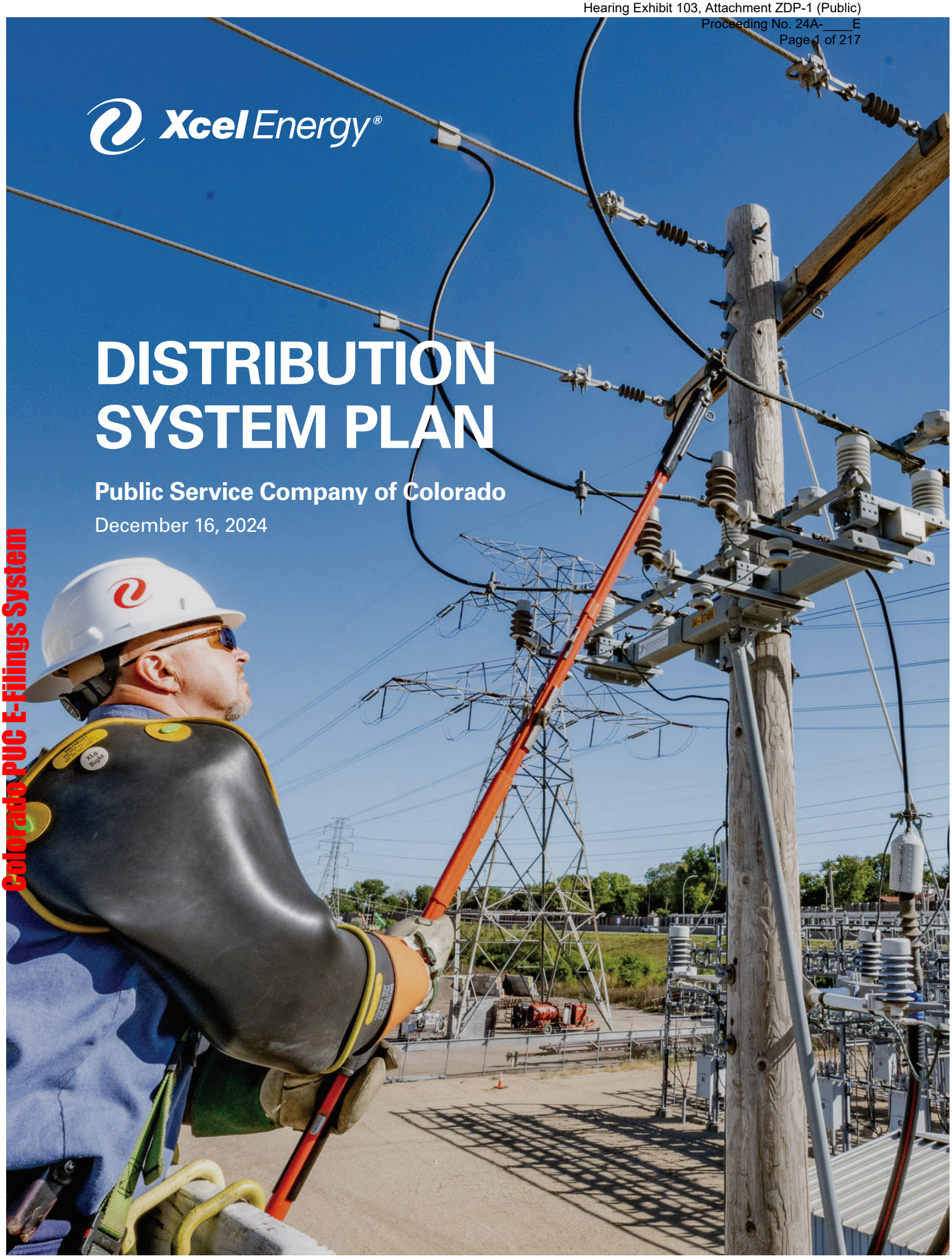
Xcel Energy®

DISTRIBUTION SYSTEM PLAN

Public Service Company of Colorado

December 16, 2024



Colorado PUC E-Filings System

TABLE OF CONTENTS

I. Executive Summary 7

II. The Evolving Utility Landscape 20

III. Integrated Planning Vision For the Grid of the Future 23

IV. Our Approach To Distribution System Planning for the Grid of the Future 28

V. The Nuts and Bolts of Distribution System Planning 34

VI. Distribution System Load Forecasting 46

VII. Grid Needs Assessment 64

VIII. Non-wires Alternative Solicitation Process 85

IX. Investment Needs and Budget 88

X. Enhancing the Customer Journey 109

XI. Climate Resiliency 128

XII. Load Flexibility, Operational Flexibility, and Infrastructure Alternatives 136

XIII. Grid Modernization and Grid Innovation 150

XIV. Stakeholder and community Engagement and outreach 194

XV. Performance-Based Framework 203

XVI. Action Plan 208

XVII. Conclusion 216

TABLES

Table 1: Summary of Capabilities Needed to Realize Vision 32
Table 2: 2025 - 2028+ Hosting Capacity Roadmap 45
Table 3: Comparison of Capacity Check Forecast to Base Forecast 54
Table 4: Kevala Forecast Scenarios 60
Table 5: Cumulative, Incremental Distribution Infrastructure Required through 2050 62
Table 6: Short-term Grid Needs 81
Table 7: Long-term Grid Needs 81
Table 8: Ratable Procurements from Grid Needs Assessment 82
Table 9: DSP Asset Health and Reliability Budget ($Millions) 96
Table 10: DSP Capacity Budget ($Millions) 96
Table 11: Infrastructure Enabled by Plan 97
Table 12: DSP Tools and Communications Equipment Budget ($Millions) 98
Table 13: DSP Mandates Budget ($Millions) 99
Table 14: DSP New Business Budget ($Millions) 100
Table 15: 2022 – 2029 Distribution Capital Budget ($Millions) 101
Table 16: 2025 – 2029 Technology Services Budget ($Millions) 104
Table 17: DSP O&M Budget 104
Table 18: Comparison of Unblurred HCA Map to Blurred Map Usage Statistics from March – December 2024 112
Table 19: Hosting Capacity Analysis Field Verifications 116
Table 20: Customer Data Elements 123
Table 21: Participation Requirements for Data Sharing Processes 126
Table 22: Current Participation in Data Sharing Processes 126
Table 23: Example consequence scores for transformers assets and exposure to extreme heat. 133
Table 24: Non-Summer Load Flexibility Call Events 137
Table 25: Evolution of DSM to Meet Distribution System Planning Needs 144
Table 26: Potential Targeted Demand Areas from the Grid Needs Assessment 145
Table 27: Customer Counts in Potential Targeted Demand Areas 145
Table 28: 2023 IVVO Benefits 159
Table 29: 2023 IVVO Infrastructure Installations 159
Table 30: DERMS Implementation Pathways 166
Table 31: DERMS Use Cases and Intended Policy Goals 169
Table 32: DSP and Grid of the Future Stakeholder Meetings 198
Table 33: Stakeholder Engagement and Outreach Budget Forecast 2025-2029 201
Table 34: FLDM Goals Reflected in Current Regulated Programs 205
Table 35: Grid Modernization Implementation Timelines 211
Table 36: Modeling and Forecasting Implementation Timelines 212
Table 37: Non-traditional Solutions and Implementation Timelines 213

FIGURES

Figure 1: Evolution of the Electric System 20
Figure 2: Evolving Grid 21
Figure 3: Overall Modeling approach for the Grid of the Future 23
Figure 4: Distribution Planning Principles 29
Figure 5: Technologies Required to Realize Grid Vision 33
Figure 6: Distribution Planning Annual Forecasting Cycle 34
Figure 7: Interconnection Process Tools Available 38
Figure 8: The Tools and Processes to Perform HCA 39
Figure 9: Load Flow Modeling Workflow 42
Figure 10: CYME Gateway Architecture 43
Figure 11: Evolution of Distribution System Forecasting 47
Figure 12: Key Recent Improvements to Distribution System Load Forecasting Process 48
Figure 13: Key Areas to Continue Forecasting Evolution 49
Figure 14: Forecast Formula 51
Figure 15: LoadSEER - Typical Load Year Example 52
Figure 16: Spatial Allocation Formula 53
Figure 17: Non-Coincident Cumulative Forecasted Demand (MW) 57
Figure 18: Distribution System Peak Transition from Summer Peaking to Winter Peaking 58
Figure 19: Distribution System Asset Hierarchy 59
Figure 20: Overview of Policy and Goal Information Used in Scenario Analysis 60
Figure 21: Summary of Kevala Electrification Impact Model 61
Figure 22: Distribution System Cumulative Capacity Investments 63
Figure 23: Comparison of the Company's Five-Year Capacity Budget to the Kevala Scenario Modeling 63
Figure 24: Distribution System Planning Divisions 65
Figure 25: 2025-2034 Aggregated Distribution System Risk Portfolio 66
Figure 26: Major Distribution Asset Deployment by Year 67
Figure 27: Boulder Division - Distribution Grid Needs 68
Figure 28: Denver Metro Division - Distribution Grid Needs 69
Figure 29: Front Range Division - Distribution Grid Needs 70
Figure 30: Gateway Division - Distribution Grid Needs 71
Figure 31: Greeley Division - Distribution Grid Needs 72
Figure 32: Mountain Division - Distribution Grid Needs 73
Figure 33: North Metro Division - Distribution Grid Needs 74
Figure 34: Northern Division - Distribution Grid Needs 75
Figure 35: San Luis Valley Division - Distribution Grid Needs 76
Figure 36: Southeast Metro Division - Distribution Grid Needs 77
Figure 37: Southwest Metro Division - Distribution Grid Needs 78
Figure 38: Sterling Division - Distribution Grid Needs 79
Figure 39: Western Division - Distribution Grid Needs 80
Figure 40: NWA Suitability Screening Process 82

Figure 41: Timing Impacts of the 2024 DSP on the 2025-2029 Project....83
Figure 42: NWA Candidate Projects....83
Figure 43: Timeline for DSP RFP Process Proposed in Inaugural DSP....86
Figure 44: Proposed Revised Solicitation Timeline for this DSP....86
Figure 45: 5-Year Action Plan Capacity Additions....97
Figure 46: HCA Roadmap from 2022 DSP Filing....109
Figure 47: Confidential Screenshot of Detailed Hosting Capacity Analysis Maps....111
Figure 48: Public Hosting Capacity Map DI Community Layer....112
Figure 49: Service Application Request Process....119
Figure 50: Utility Resilience Framework....128
Figure 51: Projected global surface temperatures under three different SSP scenarios.....130
Figure 52: Climate Risk Scoring Framework....130
Figure 53: Maximum asset exposure by 2050 (SSP2-4.5 50th percentile) for each climate hazard.....131
Figure 54: Historically observed and future projections of 30-year daily maximum temperatures across the PSCo service territory.....132
Figure 55: Vulnerability Scoring Process Diagram....132
Figure 56: Vulnerability scores distribution for overhead conductors and substation transformers to extreme heat.....133
Figure 57: Incorporation of Climate Risk into Planning....135
Figure 58: Brattle Assessment of Demand Response Across U.S. Utilities....137
Figure 59: Evolution of Renewable Battery Connect....140
Figure 60: Renewable Battery Connect Capacity and Count....141
Figure 61: Prime Time VPP Overview....142
Figure 62: VPP End-to-End System, Components, Interfaces, Project Phases & and Value Flow....143
Figure 63: Example of Mobile Battery Trailer....147
Figure 64: Advanced Grid Initiatives....151
Figure 65: Field Area Network Illustration....156
Figure 66: DERMS Organizational Interface....164
Figure 67: Application of GWAC Interoperability Stack to the Company's Enterprise DERMS 165
Figure 68: High-Level DERMS Architecture....167
Figure 69: High-Level DERMS Architecture for Flexible Interconnection Use Case....172
Figure 70: Overview of Pilot and Demonstration Project Process....179
Figure 71: A screenshot of the SAInt software graphical user interface, with simulated electric and gas networks.....180
Figure 72: Dynamic Operating Envelope Simulation Report - Active Management of Residential PV....182
Figure 73: The Four Levels of Stakeholder Engagement....194
Figure 74: Additional Capacity Provided on the Distribution System through the Plan....209
Figure 75: Five-year Action Plan....210
Figure 76: Coincident Forecasted Distribution System Peak Demand....215

I. EXECUTIVE SUMMARY

The Colorado electric grid is changing, and Xcel Energy and our customers are at the forefront of the clean energy transition to a decarbonized economy. Over the last two decades, this has meant delivering nation-leading amounts of clean electricity generated from wind, solar, and other sources to our customers. With line of sight to a carbon-free grid by 2050, the next phase entails creating the distribution infrastructure and solution set to enable customer electrification and economic growth.

Today, our customers can choose from an expanding set of options to power their lives – ranging from the fuel for the vehicles they drive, to how they heat their homes and businesses. Many of the new choices available to our customers, such as electric vehicles, reduce both the use of fossil fuels and GHG emissions. Planning for this next phase therefore requires new proactive planning processes, policies, and solutions that more granularly reflect the anticipated actions of the end users of our grid—our customers. This 2025-2029 Distribution System Plan ("DSP" or the "Plan") prepares the local grid to support the decarbonization of the transportation and heating sectors by literally connecting those sectors to a rapidly decarbonizing electric power supply. Xcel Energy's Colorado DSP, and its accompanying Grid of the Future vision for 2050, embody the critical next steps for the distribution system in Colorado.

This Plan—Public Service Company of Colorado's ("PSCo") second DSP—increases the speed and scale of grid investment through proactive planning to meet long-term system expectations and initiate foundational investments that are needed today and will prepare for the pace at which our customers adopt new technologies beyond the action period of this Plan. It does so by taking a new, customer-centric approach to forecasting that considers both historical trends *and* future technology adoption likelihood at the individual customer level to determine when and where to reinforce the grid. In doing so, this DSP will build out a local grid to enable vehicle electrification, building electrification, and distributed generation and storage, while at the same time delivering enhanced reliability, resiliency, and safety benefits. And it will do so with the recently passed Senate Bill 24-218 ("SB 24-218") providing a constructive framework to facilitate the investment needed to prepare the local grid for the future.

THE CHALLENGE: PREPARING FOR THE ENERGY SYSTEM OF THE FUTURE, TODAY

Our country's energy grid is facing a critical moment, driven by a historic shift in electricity demand, elevated risks of extreme weather events, impacts of climate change, and a continued focus on clean energy adoption. The Company's DSP is the next phase of building a more resilient local grid for Coloradans to meet these challenges.

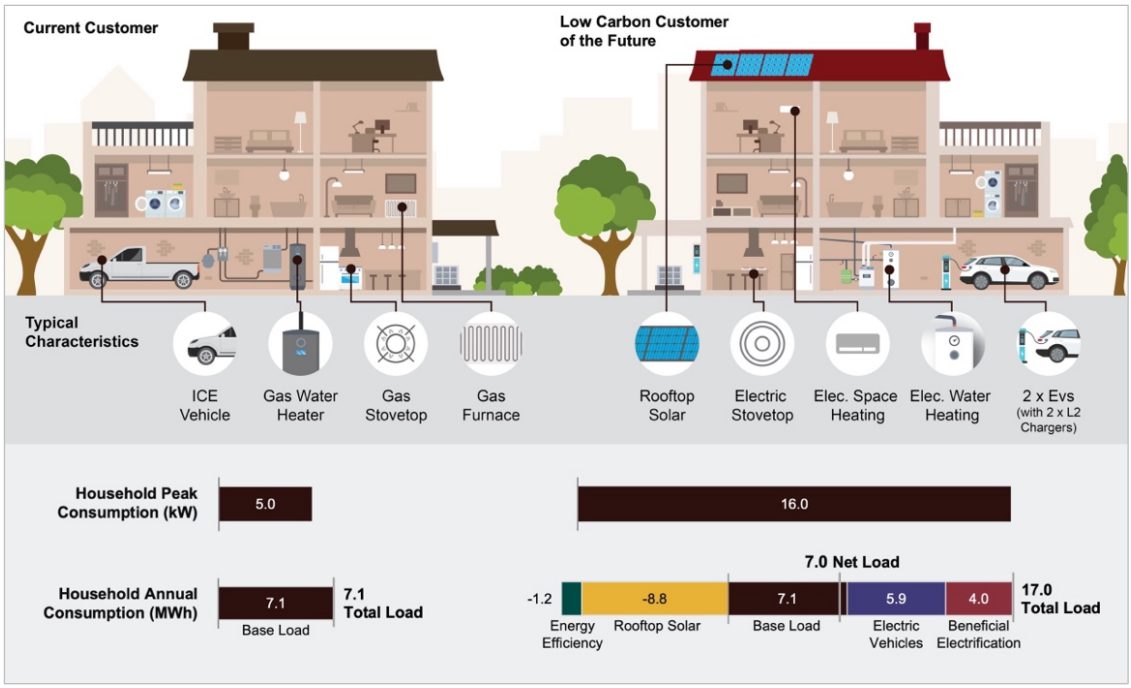
The first is the ***challenge of scale and load growth***. Overall, PSCo is facing higher load growth than seen in decades, as recently shown in the Company's Just Transition Solicitation ("JTS") filing. Specifically with respect to the distribution system, distributed customer decarbonization options—electric vehicles ("EVs"), electric heat pumps,

distributed storage, and distributed solar—are growing rapidly. There is current or projected significant growth for each end use:

- We are now at 100,000 solar PV systems and PV levels continue to grow in Colorado.
- We now have over 100,000 EVs in our service territory today, up from just over 20,000 only five years ago, and our pace of expansion is aiming to achieve our portion—about 400,000-500,000 EVs—of the State's 940,000 EV goal by 2030.
- The newer but growing modern air-source heat pump ("ASHP") market is in the single-digit thousands today but may need to grow to hundreds of thousands of installations by 2030 to achieve Colorado's clean heat goals.
- Distributed storage installations also are in the thousands today but may well grow as it has in other distributed generation ("DG") solar markets.

The distribution grid is the network to physically connect all these activities and facilitate the achievement of their corresponding policy outcomes. The scale of these resources needs to grow from thousands to tens of thousands, to hundreds of thousands, of installations over the next few years to fulfill the objectives of current plans, targets, and the overall statewide emissions reduction goals. The distribution grid as it stands today cannot support this increased scale of new demands, and we must think and act differently about the local grid for Transportation Electrification Plans ("TEPs"), Clean Heat Plans ("CHPs"), Renewable Energy Standard Plans ("RES"), and other initiatives to succeed. The proactive approach to building the local grid set forth in this DSP charts a path for supporting these policies that will ultimately facilitate the current customer of today becoming the customer of the future.

Customer of Today to Customer of the Future



The second is the ***challenge of decarbonization***. The continued growth of distributed sectors, especially EVs and ASHPs, is essential to the next stage of decarbonization. The local distribution grid delivers ever-cleaner electricity directly to customers to power these new uses. This clean electricity will come from a combination of both large-scale generation resources delivered via high voltage transmission lines as well as more locally sited distributed energy resources ("DERs"). Connecting EVs and ASHPs to the local distribution grid is essential to PSCo's decarbonization efforts, as transport and building emissions represent 38% of Colorado's current GHG emissions.[1] These reductions are guided by approved TEPs and CHPs, which in turn are essential to the State's 2030 economywide emissions reduction target of 50% from 2005 levels by 2030. The local grid must meet these needs while remaining reliable for customers and resilient in the face of extreme weather, climate change impacts, wildfire risk, and other dynamics given the critical role it plays in facilitating customers' lives and the State's economy.

The third is the ***challenge of planning to multiple objectives.*** As the economy and our customers' lives become increasingly dependent upon the local grid, there is also an expectation that power be provided with minimal interruption. With customers electing to power more of their everyday lives via the local grid—whether it be heating their homes or powering their vehicles—resilient, reliable electricity will become even more critical than it is today. The challenge is compounded by the fact that utilities are facing increasing risks related to climate change, wildfires, and extreme weather events. It is therefore essential that, as we develop solutions to simultaneously address the challenges of decarbonization and load growth, we must also incorporate reliability and resiliency into how we plan and operationalize those solutions. Doing so enables PSCo to plan and operate the grid with greater efficiency that benefits all customers.

This larger, much more complex, and distribution-intensive new era requires a robust new distribution planning, investment, and operating paradigm. And these challenges, taken together, require a significant response over the coming years and decades. It starts here with a robust DSP that implements the near-term action plan *and* a long-term vision towards the Grid of the Future, our framework looking out to 2050 across all facets of our electric business. The Grid of the Future is an overarching and long-term framework intended to overlay our generation, transmission, and distribution plans to increase customer choice and opportunities, enhance the customer experience, improve reliability and resilience, and provide a grid with higher customer value.

WHAT WE ARE WORKING TOWARDS: THE GRID OF THE FUTURE

Our customers, the Company, and the grid—together—are at an inflection point. Rapidly evolving customer needs, climate disruptions and economy-wide energy policy goals require a new approach to planning the energy delivery system of the future. The Grid of the Future represents this new approach, enabling us to plan, build, and operate a modernized, hardened, and expanded electric delivery system. It is designed to meet our

[1] *Updated 2023 Greenhouse Gas Inventory Report*, Table 2.4, Colorado Department of Public Health and Environment.

customers' needs and, equally important, *empower* customers to participate in the energy transition by giving them greater control over their energy usage.

To that end, Xcel Energy is making smart, proactive investments in generation, transmission and distribution networks that are necessary to ensure customers have access to clean, reliable power today—through 2050, and beyond. In doing so, we recognize that the future is inherently uncertain. Accordingly, to better understand the range of potential customer- and policy-driven outcomes for our system, we are examining a range of Grid of the Future scenarios. These scenarios are designed to address "what if?" views on how the energy system could look under different assumed futures.

We defined four scenarios for the potential demands on our Colorado system, ranging from an Adoption Informed scenario that extrapolates recent customer adoption trends to a scenario that assumes full achievement of the 2050 statewide emissions reduction goals. These Grid of the Future scenarios are:

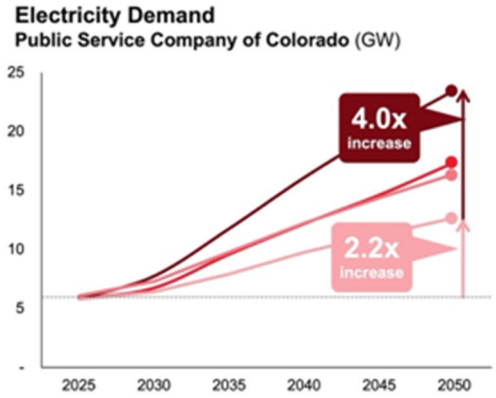
- *Calibration*: designed around current forecasting in planning proceedings, and aligned with the Base Forecast of this DSP over the action period.[2]
- *Policy-Aligned*: designed to meet updated state and local binding emissions reduction targets and binding targets established by the General Assembly.
- *Goal-Aligned:* designed to achieve state and local emissions reduction goals.
- *Adoption Informed Trajectory*: designed to meet a BAU forecast with customer adoption informed by historical adoption rates.

The early results of this scenario planning illustrate the challenges that lie ahead. Our Grid of the Future analyses reveal that as our customers electrify their vehicles, homes and businesses, and new sources of demand (e.g., large customer growth) materialize, overall peak demand for electricity on our system will grow dramatically by 2050.

[2] The Calibration scenario meets load growth in line with this DSP, which uses PSCo's Base Forecast as detailed below and in the Plan.

Long-Term Scenarios

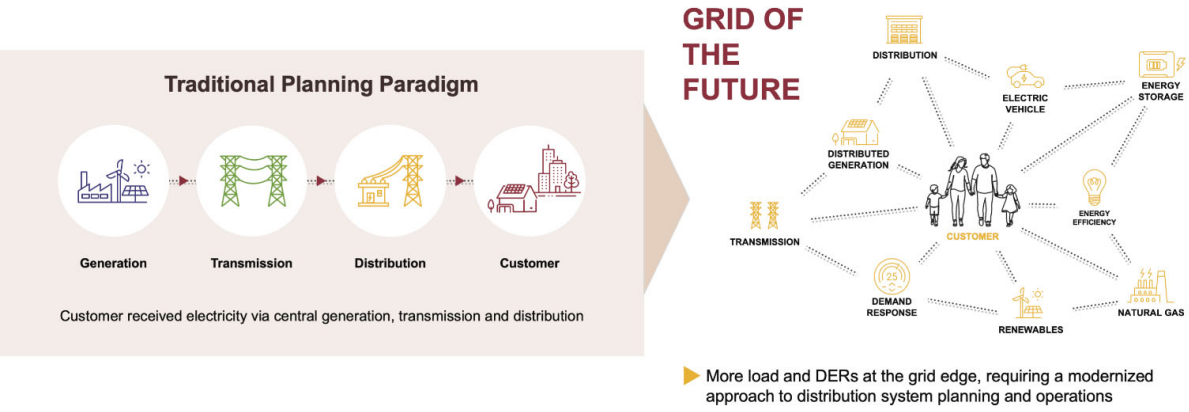
Goal Aligned	Builds on "Policy Aligned" scenario and includes growth to meet CO state and municipal decarbonization goals through 2050
Policy Aligned	Meets load growth associated with all updated Colorado state and local (binding) policies and mandates
Calibration	Meets load growth in line with our current Distribution System Plan (DSP)
Adoption Informed	Utilized forecasted adoption trajectories founded in historical adoption rates for specific and related technologies



This Plan is an installment in this longer-term effort looking out towards 2050.

Developing this Plan under the Grid of the Future framework, and consistent with SB 24-218, requires many changes, including a key one central to this DSP: reoriented, proactive planning. Traditionally, electric systems have expanded in response to incremental and relatively homogeneous customer demands. Given the scale, demand density and diversity of expected customer demands, incremental planning approaches are insufficient to meet the new expectations of our evolving energy system. PSCo needs to focus on long-term system needs when making decisions today to ensure a smooth transformation while keeping costs as low as possible. Indeed, meeting the needs of our system through 2050 requires a comprehensive retooling or rebuilding of our system; therefore, every new solution we deploy today will be designed with the future in mind. A proactive approach that is resilient to uncertainties will not only ensure we meet our customers' energy needs but will also reduce the rework and disruption that a more incremental approach could entail. Accordingly, given the scale of transformation we now face, PSCo is adopting a more comprehensive, forward-looking process—and will continue to develop it over time.

Transition from Traditional Planning to Grid of the Future Paradigm



Specifically, the Company is planning for different scenarios in a manner that is more granular in evaluating the *timing* of needed investment and also more granular in assessing the *place* for needed investment, all while anticipating the future needs created by evolving energy policy objectives. This DSP reflects this change in our forward-looking planning process.

A CONCRETE STEP TOWARDS THE GRID OF THE FUTURE: THIS PLAN

Setting the Stage: Legislative and Regulatory Background

As with many recent energy policy initiatives, Distribution System Plans resulted from the historic 2019 legislative session. Specifically, in 2019 the Colorado General Assembly passed Senate Bill 19-236 ("SB 19-236"). Among other requirements, SB 19-236 directed the Commission to promulgate rules establishing the filing of Distribution System Plans. At a high-level, the legislation directed the Commission to establish the requirements, cadence, and contents for the filing of distribution system plans, including identifying "Grid Needs" and consideration of non-wires alternatives ("NWAs") to meet those needs. We filed our first Distribution System Plan under this structure.

SB 24-218 then changed distribution system planning. In the 2024 legislative session that concluded in May of this year, the General Assembly passed SB 24-218. SB 24-218 is entitled "Modernize Energy Distribution Systems." The title is understated, but that is exactly what the bill does by recognizing that the distribution system is the foundation of the next phase of the energy transition. The bill, like this Plan, focuses on *investing* into the local grid to unlock opportunities for customers, advance reliability and resiliency, and drive achievement of State energy policy objectives. NWAs remain a part of the process; however, like our own planning, the legislation has a renewed focus on proactive planning and investing in infrastructure to create a distribution system that can facilitate customer choices in light of state policies and advance overarching policy goals. In doing so, it took a major step towards the reoriented and proactive planning needed to meet growing

needs on the local grid. SB 24-218, generally speaking, directs the development of Distribution System Plans that support numerous policies, including:

- Federal, state, regional, and local air quality and decarbonization targets, standards, plans, and regulations;
- The transportation, affordable housing, and building electrification policies of state and local law;
- Approved RES Plans, CHPs, Beneficial Electrification Plans, Demand Side Management Plans, Gas Infrastructure Plans, and TEPs.

By supporting this extensive list of policy goals, SB 24-218 creates a framework to build towards the Grid of the Future, advancing utility investment in a robust distribution system that can facilitate the achievement of state policies, other plans, and customer objectives.

PSCo's Approach to System Planning in this DSP

Developing solutions to meet identified grid needs is a multi-faceted approach that includes:

- The load forecasting process;
- Development of plans to invest in asset health and reliability;
- Implementation of new technologies; and
- Advancement of existing and new skillsets.

The objective of this approach is to support a safe, reliable, and resilient local grid prepared to meet future needs.

Historically, PSCo has forecasted load on the distribution system based on known requests for new and upgraded service.[3] Given the numerous challenges and drivers of needed investment into the distribution grid, however, PSCo has implemented a proactive planning approach into action using its LoadSEER tool.[4] By incorporating forecasted customer adoption of DERs into the load forecast, we are better able to plan for future customer usage.

The result of that approach in this DSP is our Base Forecast. Looking at it from an operational and implementation perspective, without consideration of policy objectives, the Base Forecast (using the new LoadSEER model for this Plan) shows:

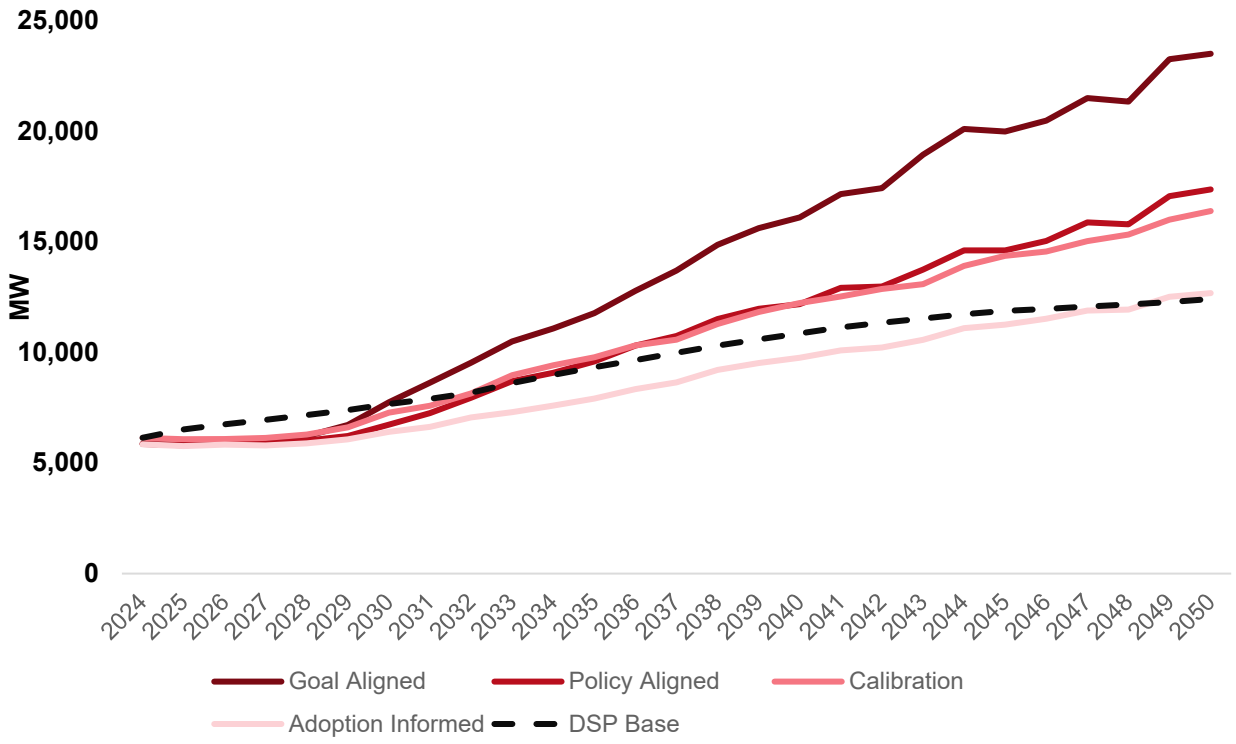
[3] This is called the Capacity Check Forecast in the Plan and only contains known growth approved by the Company's Distribution Planning team through the capacity check process for known new or upgraded electric service requests.
[4] This is called the Base Forecast in the Plan and is used by planners to evaluate the short-term and long-term capacity needs for the distribution system. In addition to accounting for the known capacity check growth, however, other growth vectors are applied to the Base Forecast to prepare the grid for the adoption of new technologies that are not yet ready to apply for service.

- How much power must be delivered;
- Where on the grid the power is needed; and
- When power must be supplied, while considering additional growth vectors.

Our previous load forecasting tool only allowed us to understand and plan around a single peak value; LoadSEER allows us to understand the loading patterns on distribution equipment for all 8760 hours of the year. The implementation of LoadSEER for this DSP enables the development of scenario forecasts to evaluate *how* varying adoption rates for different technologies impact the distribution system and *where* capacity upgrades are required.

This Base Forecast is compared below to long-range Grid of the Future planning forecasts developed by industry-recognized consultant Kevala, which are more granular and longer term than the Plan forecasts. Checking our current plans against the long-range Grid of the Future trajectories ensures steps we take now will meet not only our current needs but also are in line with what is needed in the future.

Scenario Comparison of Distribution Coincident Peak



The Base Forecast over the action period for this Plan (through 2029) tracks well over the next few years with higher Grid of the Future load scenarios that look out to 2050. This

stress test shows the Base Forecast is an appropriate foundation of the Plan and will support investments that are needed regardless of how the future unfolds.[5]

The Base Forecast lays the foundation for a set of investments and expenditures to meet the forecast and identified grid needs across eight investment type categories:

- *Asset Health and Reliability*: Projects classified as Asset Health and Reliability are related to infrastructure that is reaching the end of its useful life and is experiencing higher failure rates.
- *Capacity*: This category includes capital investments associated with upgrading or increasing distribution system capacity to handle load growth on the system and to serve load when other elements of the distribution system are out of service.
- *Tools and Communication*: This category includes tools, rights-of-way ("ROW"), communications equipment, and locate costs associated with modifications or additions to the distribution system or supporting assets.
- *Mandates*: This category includes projects to relocate utility infrastructure in public ROWs when mandated to do so to accommodate public works projects such as a road widening or realignment project.
- *New Business*: This work includes new overhead and underground extensions and services associated with extending service to new customers.
- *Transportation Electrification Plans*: This category includes investment in infrastructure and customer-facing electric vehicle programs for residential, commercial, and fleet customers included in the Company's Transportation Electrification Plans ("TEPs").[6]
- *Wildfire*: This category consists of activities included in the Company's Wildfire Mitigation Plan ("WMP").[7]
- *AGIS*: This category consists of projects included in the Company's Advanced Grid Intelligence and Security initiative.[8]

This categorization leads to the capital budget, which aligns with the objectives of SB 24-218 by making investments now that make the local grid ready to support increasing customer demand and the State's policy objectives. This overall capital budget breaks

[5] The deviations between forecast scenarios that start in 2030 are largely due to EV charging load profiles, addressed in more detail in the Plan.
[6] Certain costs associated with the Company's TEP are budgeted within the Distribution business unit. TEP costs are recovered via the Transportation Electrification Plan Adjustment Rider and addressed in TEP proceedings.
[7] The recovery of these capital costs is at issue in PSCo's WMP and not in this Plan, as explained in more detail in the Plan and Direct Case.
[8] The AGIS initiative involves the following foundational projects: Advanced Distribution Management System ("ADMS"), Advanced Metering Infrastructure ("AMI"); the Field Area Network ("FAN"); Intelligent Field Devices that include Integrated Volt-VAR Optimization ("IVVO") and FLISR (including Fault Location Prediction ("FLP"); and the Advanced Planning Tool ("APT" or "LoadSEER"). A portion of AGIS is the subject of a CPCN granted in Proceeding No. 16A-0588E for the AMI, FAN, and IVVO projects, which was then amended with respect to the distributed intelligence capabilities of the AMI meters in Proceeding No. 21A-0279E.

down by category the investments needed to meet the projected system needs, much like generation and transmission assets meet the load forecast in the resource planning context. It is a more granular and operationalized extension of the load forecast with investments by category to meet identified needs.[9]

2025- 2029 Distribution Capital Budget ($Millions)

Category	2025	2026	2027	2028	2029	Total
Asset Health & Reliability	$286	$320	$342	$364	$400	$1,713
Capacity	$289	$413	$478	$472	$427	$2,078
Tools & Communications	$13	$13	$16	$17	$17	$75
Mandates	$53	$54	$55	$56	$57	$275
New Business	$132	$137	$145	$159	$162	$736
Transportation Electrification Plan	$53	$86	$90	$106	$107	$442
Wildfire	$324	$412	$505	$455	$468	$2,164
AGIS	$27	$2	$10	$0	$0	$39
Total:	**$1,177**	**$1,436**	**$1,641**	**$1,628**	**$1,639**	**$7,522**

The local grid faces a critical moment, and this budget meets the needs of that moment. In addition, it meets the needs of our communities, with 154 total capacity projects in the Plan and 76% of them directly benefiting disproportionately impacted communities.

The simple approval of the budget for this Plan standing alone, however, cannot advance the investments needed in the local grid. SB 24-218 provides supportive cost recovery in the form of the Grid Modernization Adjustment Clause ("GMAC") tool. Accordingly, PSCo is bringing forward a proposal to commence the GMAC, consistent with the statutory framework. The proposal includes a customer-focused performance framework that ensures the utility is aligning investments with strong support of customer interconnection, energization, and flexible load opportunities. The GMAC will advance the implementation of this budget as we put cable in the ground and wires in the air, advancing this Plan as a part of the Grid of the Future.

Expanding Available Solutions through Policy and Technology

There is more to this Plan than just necessary investments in foundational utility infrastructure. This DSP brings forth a set of policy and technology solutions at new or expanded levels. The changes advanced by the General Assembly under SB 24-218, and Senate Bill 24-207 ("SB24-207") figure prominently in these new solutions, building on expedited actions already taken by PSCo and the Commission to implement a

[9] Executing on this level of investment will also require some incremental O&M based on increased staffing needs and community outreach and engagement. Over the five-year period of this plan, this incremental O&M averages a little over $6 million per year.

reformed interconnection cost policy that does not charge particular customers for higher interconnection costs that they did not solely drive.[10]

As our long-term modeling in this Plan suggests, meeting policy objectives can be achieved cost-effectively by balancing needed infrastructure investment with non-traditional solutions. This Plan represents meaningful progress towards that long-term vision as demonstrated by:

- The identification of expanded NWA opportunities;
- A proposal for targeted distribution load relief through the targeted demand area concept;
- Expansion of our successful Virtual Power Plant ("VPP") program (approximately 8 MW today of Renewable Battery Connect with another 14 MW in the queue via Aggregator DERMS); and
- New approaches to understanding how we can dynamically plan and operate our Grid by leveraging DERs in new ways.

PSCo is also pursuing these opportunities by leveraging federal funding. The Company was one of only three utilities selected to receive VPP funding by the Department of Energy to reduce the costs of advancing our VPP strategy. Taken together, all of these initiatives lay the foundation for future exploration and implementation of non-traditional solutions as a part of the Grid of the Future vision.

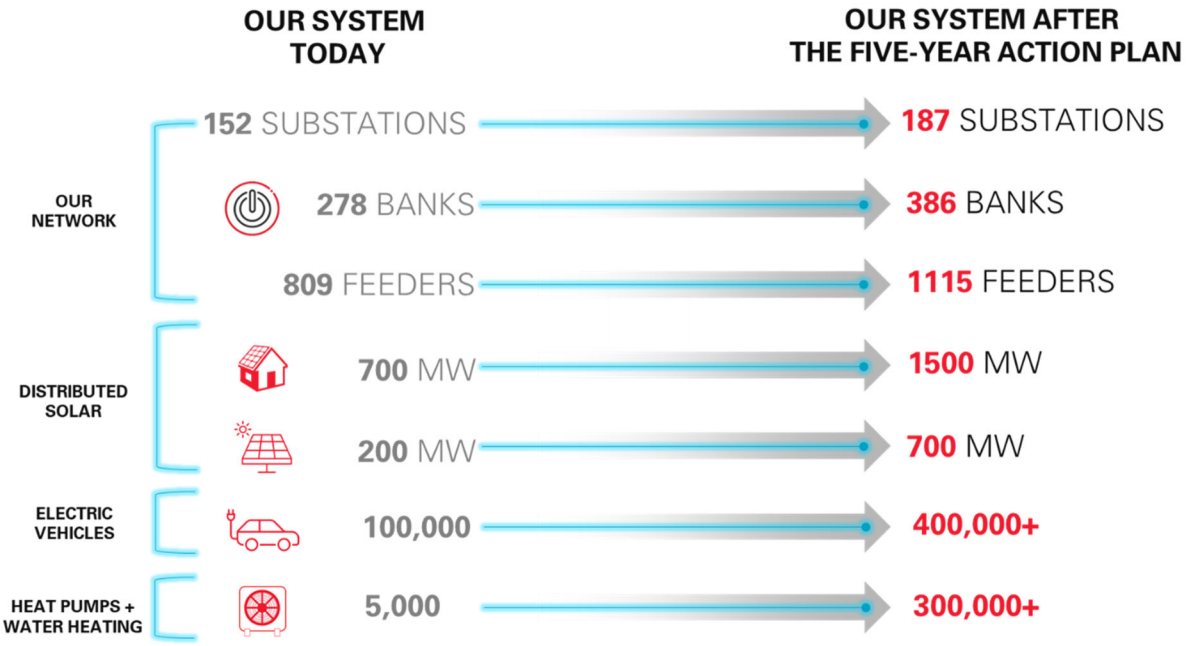
The Policy and Customer Benefits of this DSP

The benefits of a more robust local grid are numerous as a product of this DSP. First, as discussed above, the Plan will unlock significant cross-sectoral decarbonization efforts especially through vehicle and heating electrification efforts. It will also enhance resiliency and reliability of the grid, through the DSP investments, and also by complementing and supporting wildfire mitigation efforts proposed through the Company's pending WMP. Further, it will support an enhanced level of customer choice as existing and new customers contemplate a broader set of household energy choices—vehicle energy, heating energy, self-production, self-storage, and demand management programs—than ever before.

Finally, and critically, while this more robust local grid requires investment, we find that it is compatible with the objectives of affordability and cost-effectiveness. We provided a long-term rate forecast in our JTS showing that electric rates are generally aligned with long-term expected rates of inflation. That forecast was built with inputs from the same assumptions for distribution investment developed in this Plan. Further, some of the customer choices this Plan supports—in particular EVs and potentially ASHPs—are consistent with lower total household energy bills as customers shift away from expenditures on gasoline and natural gas. The figure below illustrates projected levels of these opportunities and outcomes today and at the end of the action period for this Plan.

[10] Advice Letter No. 1963, Proceeding No. 24AL-0433E.

Plan Outcomes



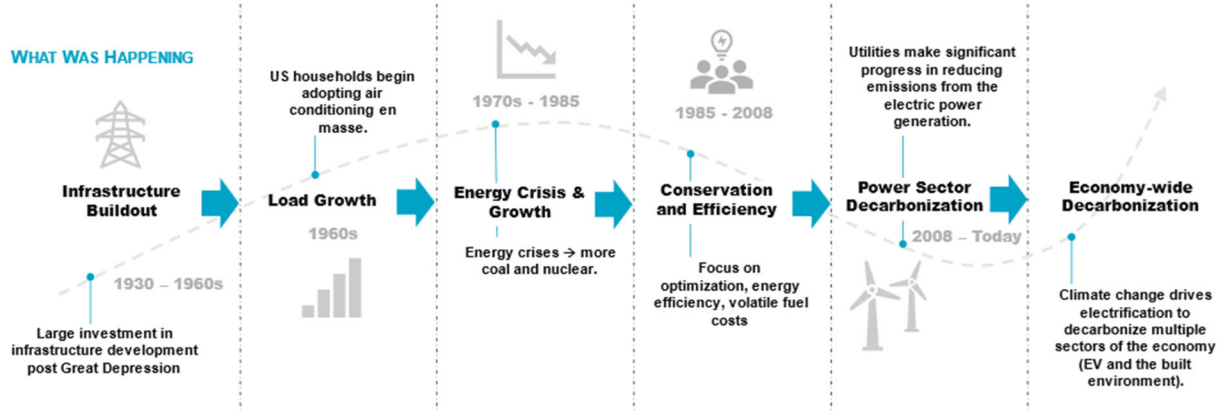
In sum, this Plan takes the next steps in building a robust local grid that is ready to support numerous policy-positive outcomes, and customer opportunities. The Company is pleased to present it to the Commission for consideration.

II. THE EVOLVING UTILITY LANDSCAPE

Xcel Energy and our customers are at the forefront of the clean energy transition. Over the last two decades, this has meant delivering nation leading amounts of clean electricity generated from wind, solar, and other sources to our customers. Today, over half of the electricity generated by Xcel Energy's system is free of greenhouse gas ("GHG") emissions and we are on track to deliver an 80% reduction in GHGs by 2030, while pursuing our goal of 100% emissions free power by 2050.

While we have been changing, the broader electric utility industry is also changing. Indeed, it is at an inflection point. Public policy goals and customer expectations to reduce carbon emissions and increase resiliency are driving a need for transformation. The role of our distribution system, and the corresponding drivers of investment, have changed significantly over time. Similarly, the expectations of our workforce have evolved– requiring new skillsets, capabilities, and approaches to planning and operating our system. Like many other electric utilities throughout the country, during times of moderate growth, the Company relied on historical trends and data to inform the distribution planning process and corresponding company investments. While this approach has enabled us to maintain safe and reliable service for our customers and communities at a relatively modest cost, our distribution system is now facing unprecedented demands that require a shift to a more proactive, forward-looking model for distribution system planning and investment. As indicated by Figure 1, this level of infrastructure expansion and modernization has not been required since the initial build out of the initial electric grid, nearly a century ago.

Figure 1: Evolution of the Electric System



In addition to the demands on the system increasing, the abilities of our distribution system also need to evolve to meet changing customer needs and expectations. While the grid of the past largely focused on delivering electricity from relatively centralized

generation resources to customer load, as shown in the graphic below, our distribution system is now being increasingly called upon as a platform to support a variety of customer decisions and energy usage choices. This shift in grid architecture has also required new approaches to manage the grid.

Figure 2: Evolving Grid

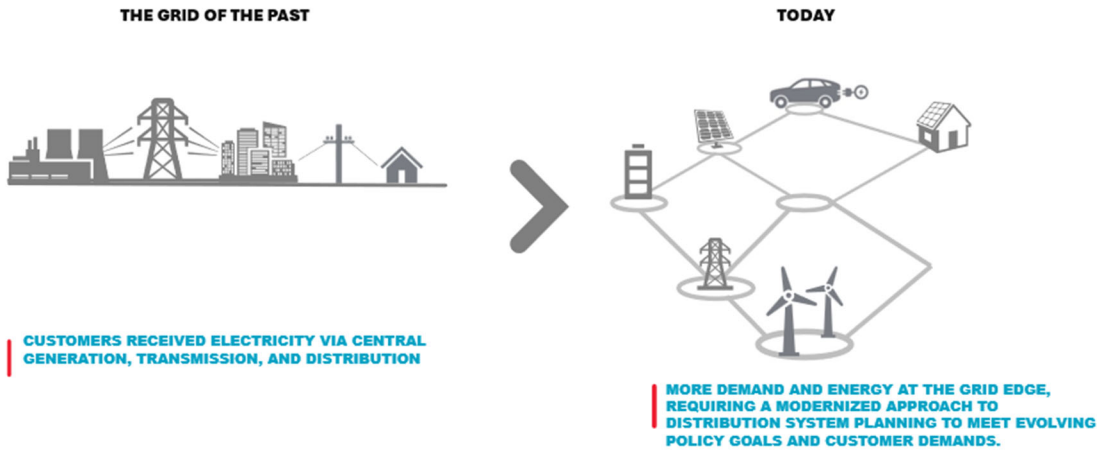


Figure 2 provides a simple illustration of how grid operations worked in the past in contrast to how we envision it will work in the future. Increasing amounts of electrification pose new and unique challenges for how we plan and operate the electric system. These challenges across both the bulk electric and local distribution systems with the electrification of heating are expected to have the most pronounced load impacts in cold climates like Colorado's where natural gas today provides most of the fuel for space heating. Further, higher adoption levels of distributed generation, energy storage systems, and electric vehicles introduce more technical complexities and require more visibility and communications. With our roles as the bulk power provider, bulk system operator, and distribution system operator, our obligation is to create a robust architecture for DER integration and the potential value they can provide to the system without distribution system adverse impacts, while also levering the best advantages of the bulk system. Upon brief examination, one can quickly see the immense system complexity created as the grid assumes greater levels of variable generation, different demand shapes, bi-directional energy flow via DERs, and an unparalleled level of customer engagement with grid operations.

Within these challenges is also an opportunity, however, for customers and the Company alike. Many of the investments discussed in this plan will be foundational to turning these challenges with grid modernization into opportunities. Our customers' decisions to pursue new, clean technologies will drive the next phase of the clean energy transition. Today, our customers can choose from a diverse set of options to power their lives – ranging

from the fuel for the vehicles they drive, to how they heat their homes and businesses. Many of the new choices available to our customers, such as electric vehicles, reduce both the use of fossil fuels and GHG emissions. Those customer-driven GHG reductions both support and are supported by the ambitious policies and goals of the communities we serve. Xcel Energy is embarking on the next phase of clean energy leadership by embracing customer's personal adoption of clean energy technologies, by building an energy system capable of accommodating growing, and more diverse, customer demand for electricity, and moving towards optimizing the flexibility gained through customer adoption to enhance alignment with the availability of zero carbon energy for the bulk electric system.

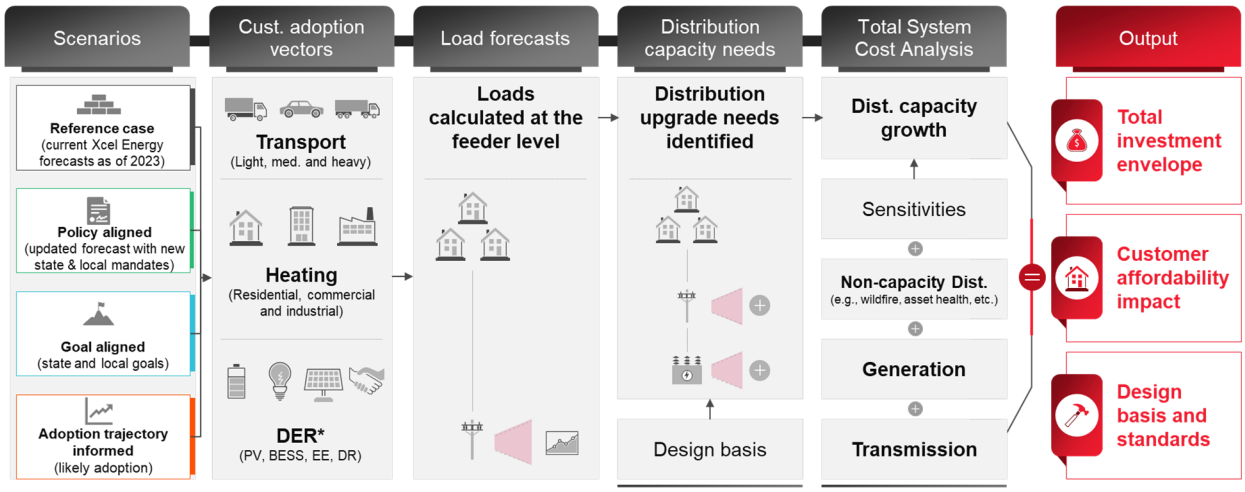
Our Plan seeks to address these challenges and unlock the opportunities presented by electrification, starting with our integrated planning vision.

III. INTEGRATED PLANNING VISION FOR THE GRID OF THE FUTURE

To successfully deliver on the strategies enumerated in this plan, we have developed an updated framework for planning and operating our system – a process to re-envision the electric system that we call the Grid of the Future. The Grid of the Future framework (Figure 3) builds upon Xcel Energy's expertise and capacity, developed over more than a century of service to our customers, to plan a reliable and resilient energy system. We are at a critical inflection point and practices of the past will not suffice for the future. Rapidly evolving customer needs, climate disruptions and economy-wide energy policy goals necessitate a new approach to plan the energy delivery system of the future.

To perform such a complex set of analyses for an integrated energy system, a framework was needed to understand how the outputs of system models could be meshed together to understand the system needs to meet each scenario. To undertake this process, the Company started from the bottom up based upon scenarios for different customer technology adoption trajectories. Next the forecasts were fed into a distribution system model that can estimate hourly load and energy demand profiles by technology type to generate unique demand profiles on feeders. The feeder forecasts were then compared against system constraints to identify potential upgrades. Further, the feeder profiles were integrated into a bulk system resource planning model to identify bulk system capacity needs for both generation and transmission.

Figure 3: Overall Modeling approach for the Grid of the Future



This new approach – the Grid of the Future – enables us to plan, build and operate a modernized, more resilient, and expanded electric delivery system. It not only positions

the Company to meet customers' needs, but also to empower customers to participate in the clean energy transition by advancing more active participation in the energy system.

EVOLUTION OF PLANNING AND FORECASTING FUNCTIONS TO ENABLE THE GRID OF THE FUTURE

The Company has made strides since the filing of its last Distribution System Plan with regard to better integrating our planning processes across functional groups as well as leveraging technology to better anticipate and plan for the needs of our system. As noted above, many of these new expectations are being directly driven by the way in which our customers choose to interact with the grid.

Leveraging Scenarios towards optimized integrated planning and investment

Decarbonization of customer-end uses requires direct decisions to be made by our customers in how they heat their homes, power their vehicles, and live their lives. This changes how our customers rely on the grid as a multi-directional system versus unidirectional. With this new relationship with our customers comes inherent uncertainties. To better understand the impact of varying degrees of customer adoption of load modifying resources, the Company has utilized a scenario planning approach in this DSP to help understand the range of potential outcomes from an infrastructure and investment perspective, which will inform our planning of the entire integrated grid. Our first steps here align and improve our assumptions today, and we expect to grow toward fully optimized investment planning of distribution, transmission, generation, and the gas system in the future.

Leveraging Bottom-up Forecasting to inform Integrated System Planning

The Company developed the Base Forecast for this DSP and corresponding capital budget for capacity investments using a granular, locationally specific forecasting methodology that includes targeted forecasts of adoption (and the corresponding load modifying impacts) of various distributed energy resources. Moving forward, it will be necessary to plan at this level of granularity. This means that the updated processes reflected in this plan will be the foundation of broader energy system load forecasting that feeds into the Company's generation and transmission planning processes. We expect this trend to continue as we further learn new methods of cross-system optimization and better ways to leverage technology to operate our system. We intend to update our planning framework as technology matures.

Leveraging technology and data and analytics to inform planning and forecasting

Many of the changes on our system are occurring at the edge of our grid. This is an area that utilities historically have had limited visibility into. However, as the Company continues to deploy new technology and advanced metering infrastructure ("AMI") across

our service territory, we are leveraging AMI data to further enhance our load forecasting, planning, and DER interconnection capabilities and processes.

Foundational to this effort is centralization of data through what the Company refers to as a "Universal Data Platform" or "UDP." The creation of the UDP facilitates access to key planning and operational data in a more efficient manner. The Company is already leveraging AMI meters and data to support several use cases that provide planning and operational benefits as described in more detail in the Grid Modernization and Grid Innovation section. In addition, the Company is continuing to explore ways to leverage AMI meters; a few examples under consideration include:

- **Exploring Machine Learning Applications for Load Forecasting** - The Company is in the early stages of leveraging AMI data in conjunction with Machine Learning. We are also exploring the development of new software tools that offer the potential to facilitate integrated planning across historical seams between transmission, distribution, and the gas system. The intent of these tools is to incorporate the granular adoption of technologies early within the load forecasting process, allowing a more consistent view of changing load patterns. Incorporating these technology adoptions early on, without losing granularity, allows for their impact to be equally represented across financial and planning applications while also expanding opportunities for scenarios.

  Internal development of "propensity to adopt" models for load modifying technologies also presents the opportunity to directly evaluate their alignment with adoption within the Company's service territory. Initial models for propensity of solar, electric vehicles, and all-electric space heating yielded an AUC ROC[11] ranging from 0.72 for heating to 0.83 for solar. The results seen for these adoption models indicate a strong likelihood that models are reliably characterizing adopters, providing confidence that they can be used to identify likely new adopters.

- **Grid Visibility Tool** ("GVT"). GVT is a tool the Company built that uses AMI interval and event data with GIS asset information to help visualize grid information such as power quality information, transformer and feeder loading. GVT is a transformational tool that provides the Company visibility to energy usage, power flow, power quality, and meter events at customer meters and distribution

[11] AUC ROC refers to the "area under the curve" for the receiver-operating characteristic curve, a common representation of the performance of classification models. In classification models, whether a data point is put into one class or another depends on where between 0 and 1 modelers set the threshold between the two classes. The rate of true positives and false positives will vary based upon that threshold and, as such, the accuracy of the model depends on relationship between those two metrics. The area under the curve captures that relationship across all possible thresholds. A model that assigns classes purely randomly would achieve an AUC ROC of 0.5, while a value of 1 indicates perfect classification. Further visualizations of this concept can be found here:
https://developers.google.com/machine-learning/crash-course/classification/roc-and-auc

transformers that previously was not possible. This will enable more proactive planning and operations on this portion of the distribution system that include identification of overloaded transformers and power quality issues that will support more proactive and improved service quality for customers.

In addition to leveraging data to enhance our planning and operation processes, the ability to better understand our system will allow us to dynamically plan for and operate our system in the future. Rather than utilizing a snapshot of system conditions, the ability to conduct more detailed modeling in conjunction with technologies like DERMS can allow us to offer more flexible connection options to customers including use cases like flexible interconnection and flexible load connections.

The Company is also informing the Commission and stakeholders about several new tools and capabilities as mentioned in the Plan that will be essential for advancing integrated planning and grid operations. This includes analysis to better integrate DERs as well as integrate infrastructure alternative planning across the gas and electric systems. While the Company is not seeking Commission approval of these tools, they are nevertheless important milestones in continuing to evolve our capabilities in line with our vision.

- **Gridsight** is a software and analytics firm that was founded in Australia. Gridsight has been helping distribution network operators in Australia leverage data and analytics capabilities to better assess the potential for network flexibility and associated mitigations like flexible interconnections. Both of these concepts are foundational to supporting higher-levels of DER penetration on the distribution system as already demonstrated by the strategies implemented by utilities in Australia to support higher small DER solar penetration in Australia.

- **encoord Inc.**, a Colorado-based company, is an energy modeling software provider that focuses on integrated energy planning across electric generation, transmission, distribution, and gas networks. This cross-commodity analysis is facilitated through their Scenario Analysis Interface for Energy Systems (“SAInt”) tool. SAInt models electric distribution systems with unbalanced power flow, electric transmission networks with balanced power flow, gas networks with hydraulic simulations, and electric generation expansion and dispatch with capacity expansion and production cost modeling. In other words, SAInt is an integrated platform that will allow the Company’s gas and electric planners to better collaborate on alternative solutions to infrastructure (e.g. non-pipeline alternatives).

PEOPLE AND PROCESS

Just as the grid is evolving, so must the personnel and skillsets of those who engineer, design, operate, and maintain the grid. We have aligned our internal workforce accordingly by integrating planning across electric generation, transmission, and distribution, as well as gas system planning, into the Integrated System Planning ("ISP") department. This alignment between Gas, Transmission, and Distribution planning is identifying risks and planning needs that overlap and solving for investment needs in an integrated manner. For instance, we now assess Beneficial Electrification and Non-Wires Alternatives ("NWAs") to identify the true cost-benefit of each mitigation compared to gas or electric investments. The ISP department in turn interacts with many other departments across the organization to gain internal and external support for plans, and transfers plans for implementation to the relevant construction and operations functions within the Company.

In this plan, the Company also seeks to add needed resources commensurate with the additional demands of the future grid within ISP, Distribution Operations, Customers Energy and Transportation Solutions, and several other departments, notably including increased community engagement resources. We aim to provide direct customer benefits in terms of better interconnection and energization experiences, among others, with these resource additions. Mr. Peuquet provides further details on the new resource requests in his Direct testimony.

To be clear, more efforts will be needed as we navigate the needs of the future grid. New skillsets, such as specialty programming and data analytics as well as diligent project management expertise with the ability to leverage Artificial Intelligence ("AI"), will be required. Also, as the scale of implementation increases through this DSP and the WMP, we expect growing engineering and construction workforce needs, whether provided by Company employees or third-party contractors. The entire industry is going through similar changes and challenges, so the Company will be competing for sought-after staff with the needed skillsets. And of course, there will be significant stakeholder engagement needed to ensure alignment as we build the future grid; as discussed in the Stakeholder and Community Engagement section of the Plan, we recognize the need to create more of an active participation opportunity for our customers and communities in the planning process.

IV. OUR APPROACH TO DISTRIBUTION SYSTEM PLANNING FOR THE GRID OF THE FUTURE

Turning specifically to distribution planning, this section outlines background, principles, planning improvements, capabilities, and technologies we are using in our integrated planning vision.

BACKGROUND AND PRINCIPLES

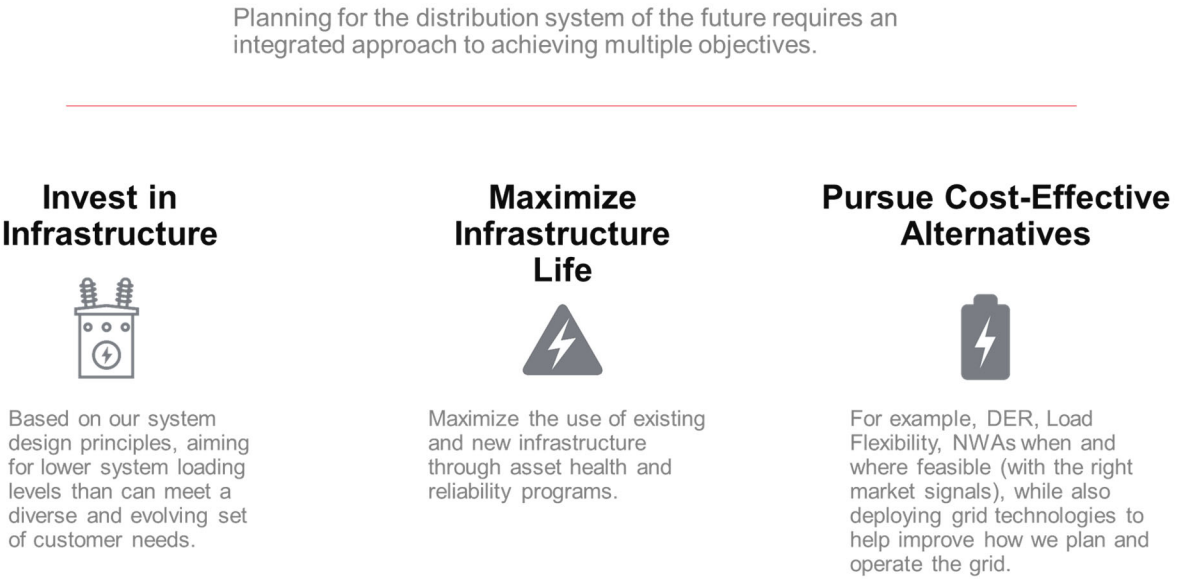
In the past, the Company has generally observed gradual, localized load growth. Mitigation projects could be implemented relatively quickly, with longer lead times often limited to large construction projects. These were predictable and relatively homogenous patterns that allowed the Company to plan for required upgrades.

By contrast, customers today are driving rapid, system-wide load growth that is diverse, and often in locations with minimal existing infrastructure. The need for short lead times to interconnection, even for very large connection requests like community solar or EV charging hubs, create a much more complex planning optimization problem due to rapid, concurrent system-wide changes.

These new dynamics have required the Company to re-evaluate approaches to forecasting, planning, and operating the grid. In response to these changes in customer load patterns, we have evolved our planning process for the Grid of the Future. And we are better understanding the ways our customers use energy today and anticipating how they may use energy in the future.

Our planning is informed by three high-level principles as indicated by Figure 4. First, the amount of change on the system requires foundational investments in infrastructure that unlocks new capacity. These investments are driven by our design standards, which balances the need to make proactive investments today with long-term needs. Second, we must efficiently maintain and maximize the use of existing and planned infrastructure through asset health and reliability programs. Finally, we recognize that the available solution set for grid needs must include expanded consideration of non-traditional solutions such as NWAs, VPPs, and other options. When and where feasible, the Company aims to deploy these non-traditional solutions. And we recognize that the distribution system is the backbone that can enable these solutions.

Figure 4: Distribution Planning Principles



EVOLUTION OF DISTRIBUTION MODELING AND FORECASTING

This more robust local distribution grid requires new modeling and forecasting tools. Greater *granularity*, down to premise-level forecasting as we have provided in this DSP through both the LoadSEER and Kevala analysis, can drive more accurate forecasts supporting more targeted investments. *Scenario planning*, also provided here in this Plan, can test multiple potential outcomes to determine whether next steps are prudent and consistent with long-term objectives. Finally, targeting not just tomorrow's capacity needs but *proactive investment* based on a longer-term, policy-calibrated approach to distribution capacity will be essential, and this DSP establishes that approach.

Modeling Granularity

This DSP includes significantly increased granularity in its modeling approaches. The Kevala analysis that is presented and complements the Base Forecast driven by LoadSEER modeling, is modeling "bottom up" from the individual customer premise level, offering greater locational or load granularity and enhanced accuracy for DER adoption propensity. The time granularity is also increased from through the use of the LoadSEER tool that can model 8760-hour load curves, versus previous modeling tools that focused on peak hours per distribution asset.

Scenario Planning

This DSP adopts a scenario planning approach to test the robustness of the Base Forecast that we have advanced for approval. We defined four long-term scenarios for the potential demands on our Colorado system. The long-term scenarios range from an Adoption Informed scenario that extrapolates recent customer adoption trends to a scenario that assumes full achievement of the 2050 statewide emissions reduction goals. These long-term scenarios are developed as part of our Grid of the Future work, framed as follows:

- *Calibration*: designed around current forecasting in planning proceedings and aligned with the Base Forecast of this DSP over the action period.[12]
- *Policy-Aligned*: designed to meet updated state and local binding emissions reduction targets and binding targets established by the General Assembly.
- *Goal-Aligned:* designed to achieve state and local emissions reduction goals.
- *Adoption Informed Trajectory*: designed to meet a BAU forecast with customer adoption informed by historical adoption rates.

The results of the Scenario Planning exercise indicate that the Company's Base Forecast and Five-Year Action Plan are well-supported across the potential long-term trajectories of each of the modeled scenarios.

Proactive Planning and Investment

Developing this Plan consistent with SB 24-218, and under the Grid of the Future framework, requires many changes, including a key one central to this DSP: reoriented, proactive planning. Traditionally, electric systems have expanded in response to incremental and relatively homogeneous customer demands. Given the scale, demand density and diversity of expected customer demands, incremental planning approaches are insufficient to meet the new expectations of our evolving energy system.

Instead, PSCo has focused on balanced immediate demands and long-term system needs when making decisions today to ensure a smooth transformation while keeping costs as low as possible. Indeed, meeting the needs of our system through 2050 requires a comprehensive retooling or rebuilding of our system; therefore, every new solution we plan and deploy today will be designed with the balance of today future in mind. And what we plan *to* is as important as the futures we plan *for*. Accordingly, the physical build out of the distribution system to meet the growth of the future is planned to align with the Company's 75% distribution planning standard. Building the distribution system to this planning factor enables the system to absorb growth as its being built out and ensures

[12] The Calibration scenario meets load growth in line with this DSP, which uses PSCo's Base Forecast as detailed below and in the Plan.

operational flexibility that enables resiliency and reliability.

A proactive approach that is resilient to uncertainties will not only ensure we meet our customers' energy needs but will also reduce the rework and disruption that a more incremental approach could entail. Accordingly, given the scale of transformation we now face, PSCo is adopting a more comprehensive, forward-looking process.

Incorporation of Major Policy Drivers in Scenario Forecasts

One of the factors of a proactive planning approach is enhanced incorporation of policy drivers into the modeling. The Base Forecast provided in this DSP incorporates several major policy drivers to align with state policy and to proactively plan for the adoption of these technologies. These forecasts were developed at a system-wide level and then translated into geographically specific adoption forecasts of load-modifying DERs using the LoadSEER software. In other words, the forecasts used in this DSP consider the load modifying impacts of future DER adoption. These load modifying impacts are therefore accounted for in the Company's Grid Needs Assessment and ultimately the capacity capital budget. The Base Forecast accordingly includes the CHP electrification forecast, the Demand Side Management efficiency and demand response forecasts, the TEP electric vehicles forecasts, and onsite solar forecasts. These forecasts are described in greater detail in the Distribution System Load Forecasting Section below. In addition, the Scenarios we modeled with Kevala include alternative policy and goal-driven adoption trajectories aligned to different levels of customer technology adoption.

GRID ARCHITECTURE AND INTEGRATED SYSTEM DESIGN

As the electric grid becomes increasingly decentralized, it is critical that the Company's long-term vision for the Grid of the Future encapsulates key decisions related to the integrated distribution design and the overall grid architecture. This includes both the physical infrastructure as well the digital and other non-physical aspects of the grid (communications and networking layers). While the physical infrastructure is reflected in the Company's Base Forecast, many of the enabling technologies that will allow the Company to consider a more comprehensive set of solutions are reflected in the Grid Modernization and Grid Innovation section of this Plan.

CAPABILITIES TO REALIZE THE GRID VISION

Realizing the grid vision that results from the more proactive planning performed by the Company in its Grid of the Future framework and this Plan requires more than modeling. It takes new capabilities, and the capabilities required to achieve the Company's grid vision will go beyond typical capabilities, skillsets, and tools commonly found in many electric utilities today. The Company is in the process of completing several foundational investments in enabling technologies and corresponding architecture that are required to

facilitate the development of more advanced future capabilities. A summary of these capabilities is provided as Table 1.

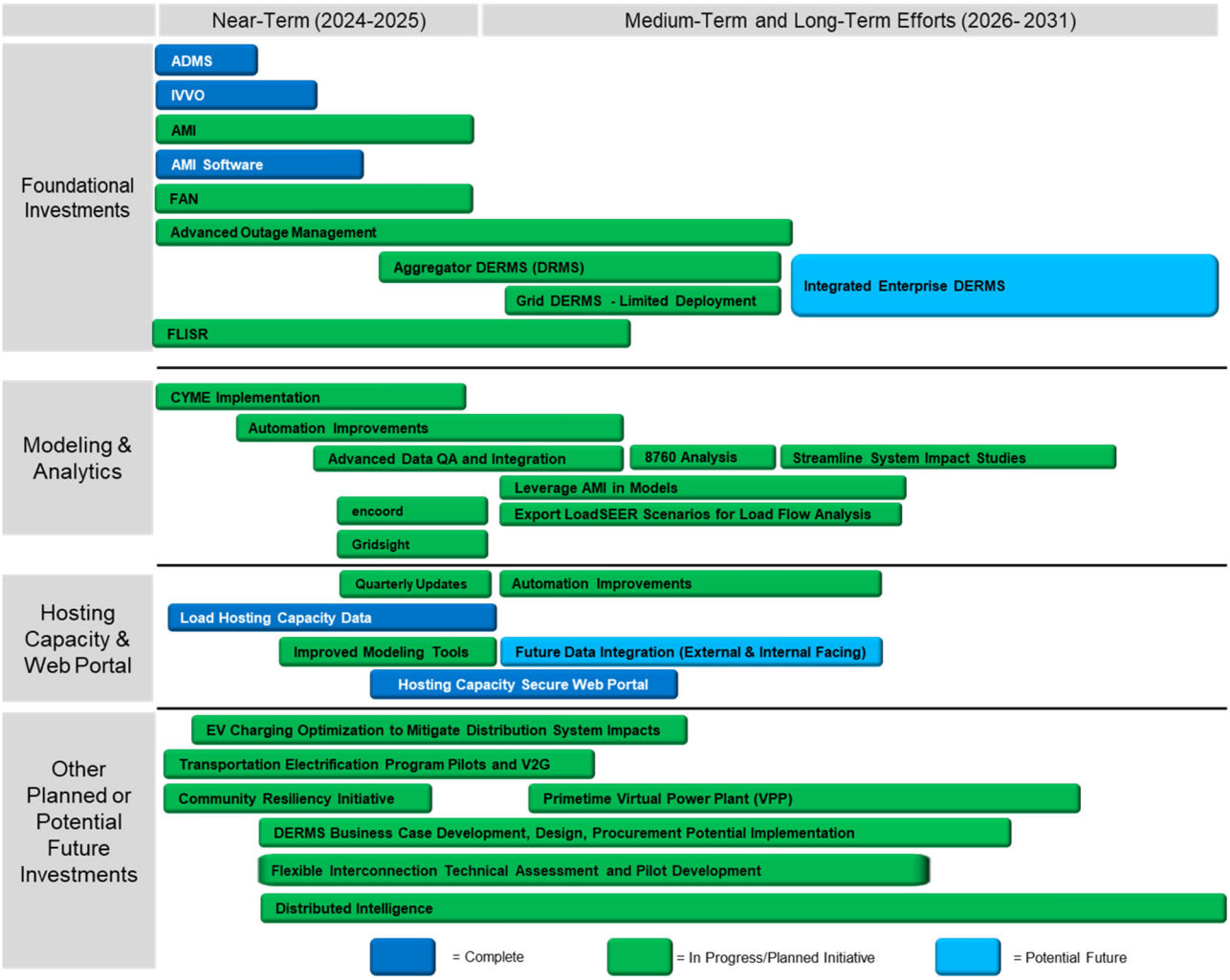
Table 1: Summary of Capabilities Needed to Realize Vision

Near-term (2025)	Mid-Term (2026 – 2029)	Long-Term (2029+)
Customer Experience • Improve transparency, process and tracking of customer load request and energization. • Modernize and integrate load flexibility portfolio via Aggregator DERMS • Establish business processes and technical requirements for flexible load and interconnection process. • Implement monthly HCA **Modeling, Forecasting and Analysis** • Finish Implementation of CYME • Continue to refine and enhance distribution load forecasting process. • Develop automation for power flow modeling and distribution analyses (CYME) • Integration between power flow and load forecasting software **Data Integrity and Availability** • Enhance the precision of asset information and geospatial data. • Improve distribution visibility and situational awareness	**Customer Experience** • Develop additional load flexibility and flexible interconnection offerings. • Automate as much as possible the load and generation interconnection study processes. • Engineer, Construct and maintain a distribution system below a 75% utilization rate. **Modeling, Forecasting and Analysis** • Develop 8760 and time series analyses. • Develop risk and mitigation process for scenario forecasting. • Further integration of Climate Risk into planning processes • Develop a 5-year distribution system load flow model. **Data Integrity and Availability** • Incorporation of AMI data set into load forecasting process • Establish data governance processes to ensure long-term data integrity	• Enable DSO model. • Implement a single automated interconnection portal for load and generation.

Similarly, the Company is presenting an updated illustration in Figure 5 below of the technologies that will be necessary to realize this Grid Vision. Many of these foundational

technologies have either already been deployed or are in the process of being deployed. The Company is continually seeking new ways to leverage these foundational investments to provide more value to our customers and the grid as discussed further in the Grid Modernization and Grid Innovation Section of the Plan.

Figure 5: Technologies Required to Realize Grid Vision



V. THE NUTS AND BOLTS OF DISTRIBUTION SYSTEM PLANNING

PSCo's Distribution System Planning organization conducts an annual planning process that begins in the fall. While the discrete steps in the process depicted by the figure below have remained relatively constant, many aspects of these steps have become more sophisticated and expansive over time. For example, the Company's distribution system load forecasting process has evolved significantly since the Company's inaugural Distribution System Plan as discussed in the next chapter of this Plan. Similarly, during the mitigation development phase of the distribution planning process, the Company now considers non-traditional solutions including non-wires alternatives, alongside traditional infrastructure solutions. This process begins with developing scenario forecasts, identifying the risks on the system (i.e. Grid Needs), and ultimately results in developing projects to mitigate the risks. Once these projects are approved, the Company works with our design and construction colleagues in Distribution Operations to implement the needed projects.

Figure 6: Distribution Planning Annual Forecasting Cycle



Historically, and as described earlier, the planning organization conducted a top-down distribution system load forecasting exercise to estimate future demands of the system. This top-down methodology was primarily informed by a combination of known load

requests and historical demand patterns recorded through the Company's SCADA system. Since the Company's inaugural Distribution System Plan, the Company has evolved our forecasting process significantly to better prepare our system for new and increasing customer expectations.

The evolved forecasting process accounts, as it has done in the past, for known load growth on specific areas of our system that typically originate through the capacity check process. Additionally, the new forecasting methodology includes the load modifying impacts of future DER adoption. To determine these locationally specific impacts of DER, the Company uses LoadSEER software to perform a spatial allocation process whereby system-level forecast of DERs are allocated to specific geographic locations that correspond to the connectivity of the distribution system. The combination of these two approaches enables the Company to produce a distribution system load forecast that is both more spatially and temporally granular. These process changes specific to LoadSEER are discussed further in Section VI of the Plan.

SYSTEM ASSESSMENT AND DISTRIBUTION FORECASTING

The Company performs an annual review of historical system loading data for all distribution feeders and substation transformers. Feeder and substation transformer peaks are recorded on a "net load"[13] basis – that is, the impacts of distributed energy resources are already reflected in SCADA reading. Distribution System Planners scrub the historical SCADA data to remove or correct abnormal, anomalous, or missing data. The data review and validation processes are a critical first step in ensuring that forecasts are generated based on accurate historical loading data. The methodology and tools used to generate the distribution load forecasts are explored in more detail in Section VI of the Plan.

RISK ASSESSMENT

The next step of the load forecasting process is to compare the forecasted load growth (inclusive of load modifying impacts of forecasted DERs) against equipment ratings and planned load limits to identify and quantify the risks on the distribution system, specifically, distribution feeders and substation banks. Two risk types are analyzed for the distribution system: N-0 overload and N-1 contingency risks.

N-0 overload risks occurs when the demand on a feeder or substation bank exceeds the N-0 planned load limit when the distribution system is operating in the normal configuration. Normal configuration is when all feeders and transformers are in operation and supporting the capacity of the distribution system. N-0 overloads are the most severe risk type and are prioritized for capital funding. If a distribution feeder or substation

[13] Due to limited visibility for all DER resources, the true native load is not able to be quantified.

transformer were to fail or become unavailable for operation[14], the distribution system would be in an N-1 state.

N-1 contingencies occur when a distribution feeder or a substation bank are removed from operation, whether planned or unplanned. N-1 risks occur when the load normally served by the inoperable asset is not able to be restored through feeder and/or bank ties without exceeding the continuous rating of the distribution equipment. The customers subjected to this N-1 outage would be without power until repairs are made, and the system is restored to an N-0 state. The system's ability to maintain operation in an N-1 state leads to greater system reliability and resiliency.

The risk assessment is time-series analysis to quantify the magnitude, consecutive hours and annual hours that the risk is present. Once the risk assessment is completed, Distribution Planners evaluate the risk portfolio and begin developing projects to mitigate the risks.

MITIGATION DEVELOPMENT

Based upon the results of the Risk Assessment, Distribution Planners develop mitigations (projects) to address the risks on the distribution system. Planners attempt to cluster risks to minimize the number of projects needed to resolve the grid needs. Mitigations undergo risk scoring and a peer review process to help refine the solutions and to ensure the system risks will be fully resolved as a result of implementing the project. Mitigation solutions developed by Distribution Planners can be wired solutions (new feeders, substation banks or new substations) or non-wires alternatives. Once all mitigations are identified and peer reviewed, the project is further refined, into an "Electric Distribution Planning memo"[15] ("EDP Memo") for distribution feeder projects and a "Necessities and Benefits" ("N&B") document for substation projects.

DESIGN AND CONSTRUCTION

Distribution Planners develop the scope of work needed for each project and then work with designers and construction crews to ensure the project is implemented according to the initial scope. This typically begins with a field walkdown to evaluate the scope of work in the field to ensure constructability and project feasibility. Where projects contain both substation and distribution scopes, project managers from the distribution, substation, and transmission organizations work together to ensure close coordination and deliver the project efficiently. Deviations from the initial scope, whether due to field obstacles or

[14] N-1 contingencies can be planned (construction, maintenance) or unplanned (outages, equipment failure).
[15] EDP Memos are typically developed for projects within the first two years of the capital budget for distribution feeder projects to allow for the design and procurement of necessary equipment. Substation projects take longer to implement and require EDP memos beyond the second year.

permitting challenges, are revised, and reflected, along with the cost changes, in the distribution budget. The budget is reviewed and updated annually to reflect changing system risks and needs.

HOSTING CAPACITY ANALYSIS

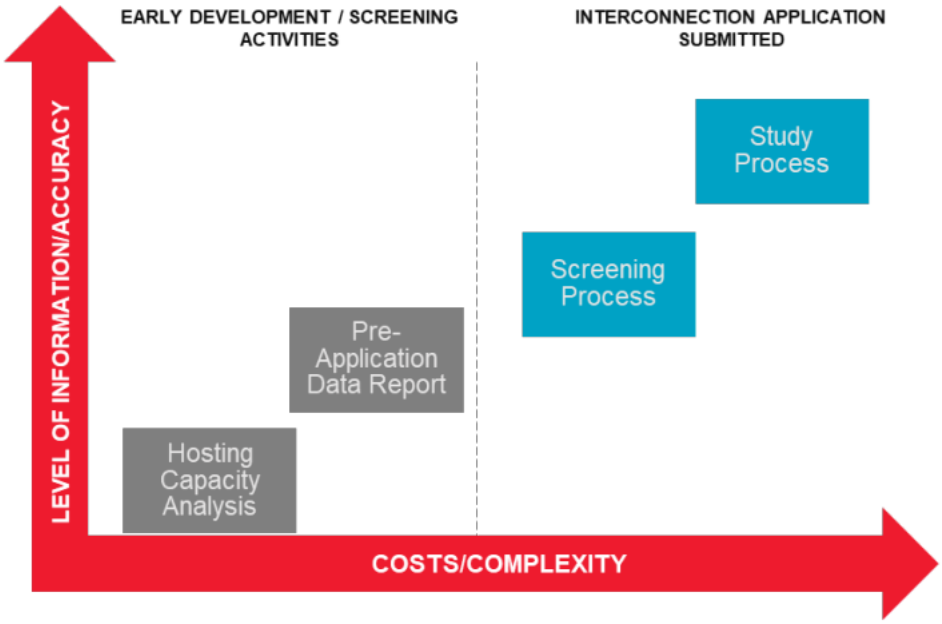
Hosting Capacity Overview

"Hosting capacity" is defined in Distribution System Planning rule 3527(k) as:

> [T]he amount of distributed generation, including distributed generation paired with non-exporting battery storage (and additional technologies including exporting battery storage to the extent reasonably feasible to model), that can be interconnected to the distribution system at a given time and at a given location under existing grid conditions and operations, without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring electric infrastructure upgrades.

Hosting Capacity Analysis ("HCA") is one of many tools available to stakeholders to help guide development activities. HCA is a high-level initial screening tool that supports the interconnection of DER by identifying areas of the grid where interconnections likely won't trigger system grid upgrades. Hosting Capacity approximates available interconnection capacity throughout the distribution system. Due to the nature of the analysis, further validation through engineering screening and analysis are needed to evaluate the specific point of interconnection, the size of the DER (kW), and operational attributes of the proposed interconnecting distributed energy resource. However, even with this level of imprecision, HCA still provides useful information to stakeholders because it can be conducted on a system-wide basis to help guide DER development before an interconnection application is submitted. The figure below provides a visual of this process.

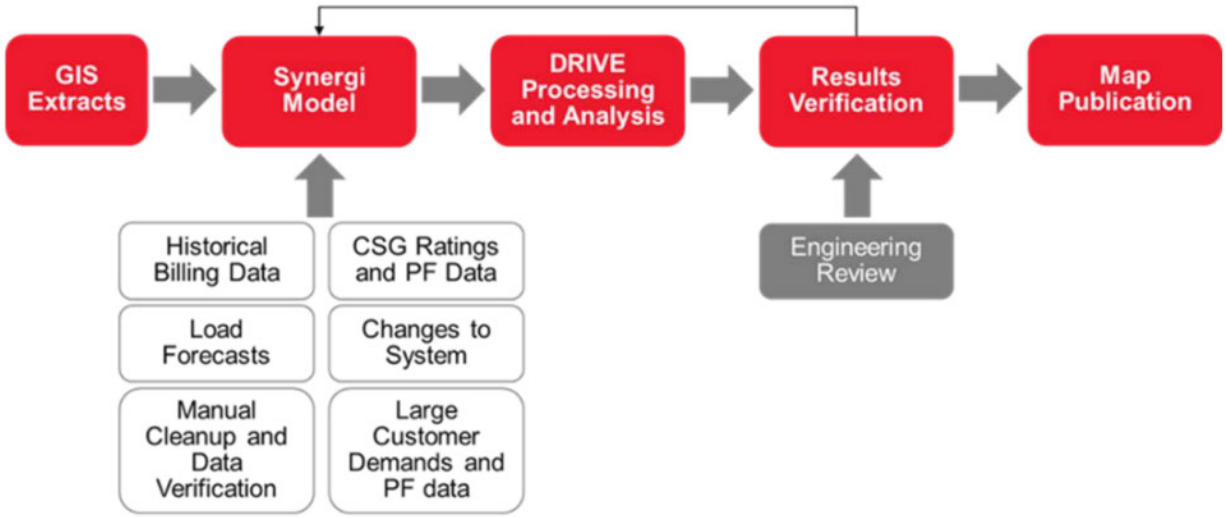
Figure 7: Interconnection Process Tools Available



HCA Tools and Methodology

The Company uses several tools and processes that rely on numerous data inputs to complete the hosting capacity analysis process, as depicted by Figure 8, below. While we believe it is important to provide the information from the HCA process at no cost to our customers to help them better inform DER interconnection decisions, it is important to recognize that the HCA process is complex and time-consuming, which results in real costs to the Company. The following section summarizes the key tools and processes needed to produce the hosting capacity maps.

Figure 8: The Tools and Processes to Perform HCA



EPRI DRIVE and MAI

The Company uses the EPRI DRIVE tool to conduct our HCA. EPRI DRIVE is the tool that computes the hosting capacity analysis and produces the results that are ultimately mapped on the Company's public and private web portals. The DRIVE MAI tool is an EPRI product that converts Synergi Electric load flow models into the DRIVE format to enable the hosting capacity analysis to be performed.

The analysis is based on EPRI's streamlined hosting capacity method, which incorporates years of detailed hosting capacity analysis by EPRI to screen for voltage, thermal, and protection impacts from DER. Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations to determine the minimum and maximum range of hosting capacity. The electric system's hosting capacity is mainly impacted by DER location, type and system size. EPRI's method is intended to strike a balance between speed and accuracy. While it does not replace a detailed analysis, it provides more value than a traditional interconnection screening, such as the criteria found in the FERC Small Generator Interconnection Procedure ("SGIP"). The result is a more complete and efficient way to understand a feeder's ability to integrate new DER at multiple points on the distribution system.

Synergi Electric

Today, our hosting analysis relies on feeder models generated in our Synergi Electric load flow software tool. The connectivity and construction information for these models primarily comes from our Geographic Information System ("GIS"), but is supplemented with other data, including customer billing, SCADA, system impedances, and equipment settings. It should be noted that Hosting Capacity is a medium voltage feeder level

analysis and does not take into account the low voltage secondary equipment, the high and medium voltage substation equipment, and any upgrades that would be identified during an interconnection study, such as upgrades to address 3V0 protection.

Internal Quality Assurance Process

The HCA process is complex and requires numerous steps prior to publication. As noted above, distribution feeder models are built by distribution engineers using Synergi Electric software that combines GIS data, equipment and system parameters, and historical loading data to produce functional models representing previously experienced system conditions.

These models are quality checked by the engineering team and are converted to the EPRI DRIVE format using the EPRI MAI Tool to process the analysis. During this conversion, standard thresholds are set to ensure the MAI conversion produces acceptable models. Models that violate these thresholds are revised in Synergi and converted through the MAI tool.

Once all models have successfully been converted to the DRIVE format, the models are processed in the EPRI DRIVE tool, which performs a load flow and short circuit analysis for peak and minimum daytime loading scenarios to produce the results. The results are reviewed by the engineering team to validate the results using the following methods:

- Feeder results that are all zero are flagged as erroneous results. These models are reprocessed in Synergi to identify the source of the input data errors and repeated through the process detailed above.
- Feeders with results that differ from the previous year's HCA analysis are flagged to be reviewed by the engineering team. The models are reviewed to determine whether there is a valid reason for the changes in hosting capacity, such as new DER interconnections, system reconfigurations, or changes to the feeder loading.
- The limiting element for the Hosting Capacity results are reviewed to determine if they are appropriate.

Once the QA process is complete, the Hosting Capacity results and the data for the popup menu details are provided to our geospatial information systems team. From that data, the GIS team creates the heat map and popup menus in ArcGIS format and publishes the map online.

DISTRIBUTION LOAD FLOW MODELING TOOL UPGRADES

Distribution Load Flow Analysis Tool Solicitation

Distribution load flow analysis is a fundamental component of distribution planning, and the Company has taken recent steps to improve its load flow analysis tools and capabilities. After the completion of the 2022 Distribution System Plan, a team of technical subject matter experts developed a set of functional requirements and an overall architecture for the modeling tools needed to enable advanced functionality and automation for distribution system analyses. In Q3 2023, the Company conducted a request for proposals ("RFP") to evaluate different vendors' capabilities in alignment with this distribution vision, focusing on five key areas.

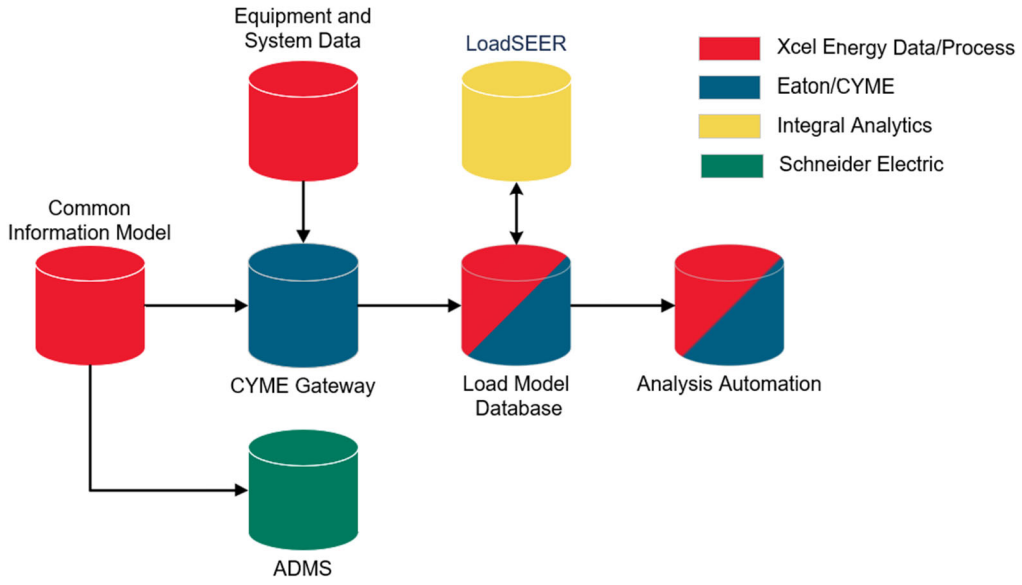
1. Align Operational and Planning Models and Data sources
2. Automate Model Building Process
3. Ensure Data Quality and Model Integrity
4. Enable Bulk Distribution System Analyses
5. Streamline Existing Business Processes

The Company performed several rounds of evaluations with bidders to better understand how specific capabilities performed related to the functional requirements. Ultimately, the Company chose Eaton's CYME Distribution Software platform to help enable the Company's vision. In Q4 2023, The Company began working with Eaton to develop the scope of work and mapping the data sources needed to accurately model the distribution system for all operating companies. The tool that would be delivered is Eaton's CYME Gateway solution, which is a data extractor and model compiler that streamlines and automates much of the model building process.

Distribution Modeling Architecture

The overall architecture of the project is outlined in Figure 9 below. Within this simple architecture is a complex integration of data sources to align and automate the model building and distribution analysis process. There are three key components that are critical in implementing this architecture: Common Information Model, CYME Gateway, and Load Model Database.

Figure 9: Load Flow Modeling Workflow



The **Common Information Model ("CIM")** is a utility industry standard that aims to standardize and better enable data to be shared between applications. The Company developed a CIM model of its distribution system initially through the AGIS program that was foundational to establishing the ADMS platform. The Company has further expanded a CIM model to every Operating Company's distribution system to further advance our deployment and capabilities within ADMS.

The Company chose to use the CIM model to build the foundation of the load flow software connectivity and mapping models for two primary reasons. The first reason is this allows the models used by Operations within ADMS and the Planning models used within CYME to have the same foundation to ensure that the assumptions and underlying data is the same. This also allows us to bypass pulling this information directly from GIS which contains errors and missing information. This was a large obstacle in our previous manual model building process that will be removed once this is implemented.

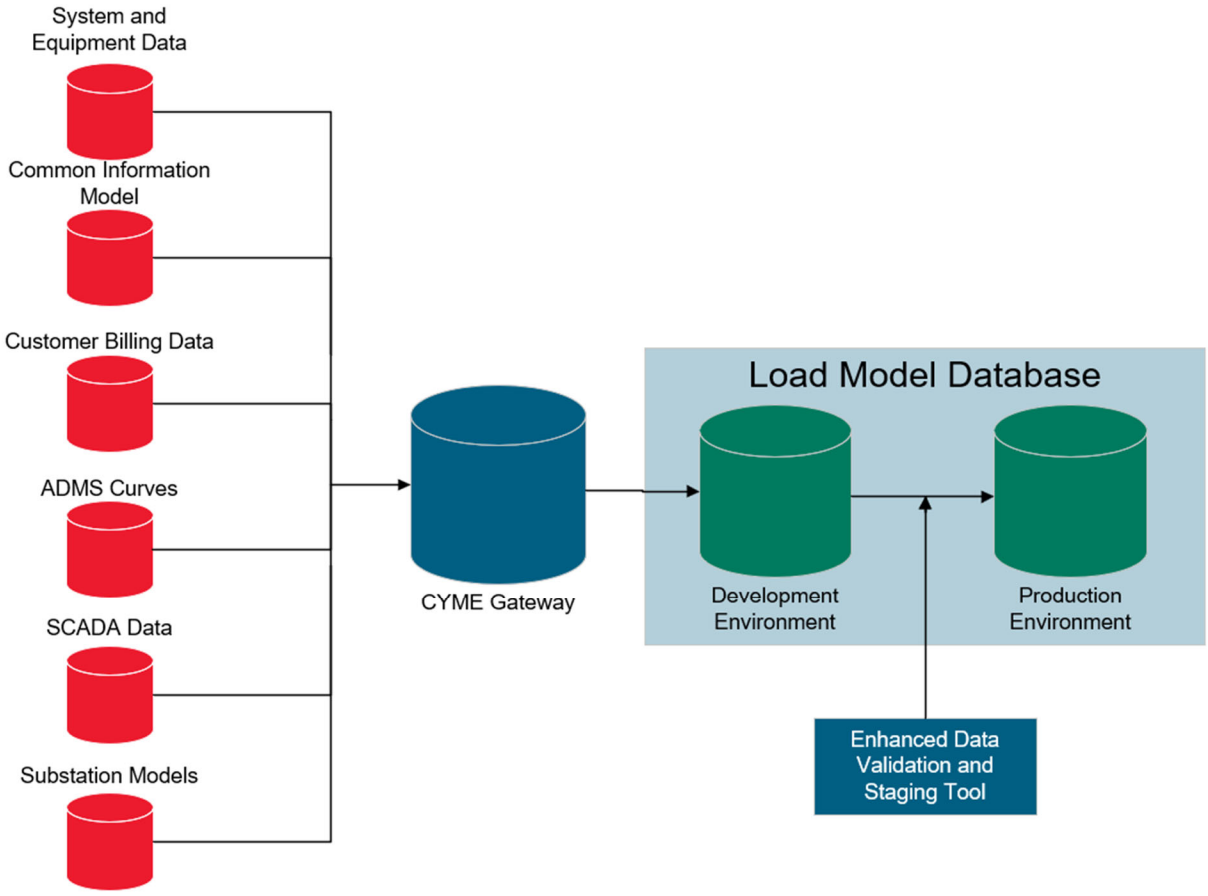
The CIM model is refreshed daily to ensure operational ADMS models are accurate and current. While this refresh cadence will continue for the CYME model building process, the Gateway will refresh models every month, in which case only the most recent CIM extract for a given feeder will be extracted.

The **CYME Gateway**[16] **("Gateway")** will be the workhorse of the model building process. The CYME Gateway tool is a custom designed data compiler and model builder based

[16] CYME Gateway solution

on the Company's data sources, tools, and processes. The Gateway extracts data from numerous systems and automatically generates several load models for each distribution feeder. The initial process will run the Gateway every month to refresh models and to prepare for more frequent hosting capacity analyses and publications. The overall architecture for Gateway is displayed in Figure 10.

Figure 10: CYME Gateway Architecture



Previously, building models required engineers to manually enter much of the information in the red data sources in Figure 10. The Gateway now automatically extracts this information, performs quality assurance measures on the input data, and compiles the distribution feeder models, each with five different loading scenarios that are commonly used in distribution analyses:

1. Daytime Peak
2. Summer Peak
3. Winter Peak

4. Daytime Minimum
5. Absolute Minimum

Automatically creating these load models drastically streamlines many distribution analyses, including DER interconnection studies, capacity checks studies, new project development, electrification studies and many more. While significant effort goes into preparing final feeder models through the Gateway tool, additional details are needed to be imported into the models before they are operational. Additionally, ensuring published models are validated is critical to enabling automation. Therefore, Gateway models are published to a development environment, and additional quality assurance measures conducted by engineers are taken before publishing the models in a production environment of the Load Model Database, as detailed in Figure 10**.**

With respect to the **Load Model Database**, before publishing feeder models to the production database, the extracted feeder models from the Gateway are screened using Eaton's Enhanced Data Validation and Staging tools to better streamline model publications, shown in Figure 10. These tools allow engineers to update certain parameters into the load model database and validate the data to ensure the production database is maintained properly. Logs are produced during the Gateway extraction and Staging processes to allow the Company to better understand bad/missing data to correct the data in their originating sources.

The Load Model Database will be linked to LoadSEER to provide the geospatial model leveraged by the tool. This will help maintain capacity check models and will enable bulk system and scenario studies in the future. This integration is critical to enabling additional functionality within the Modeling and HCA Roadmap.

The Load Model Database is the goal of this project as having an established database of vetted models enables automation of numerous processes and analyses.

Modeling and Hosting Capacity Roadmap

The Hosting Capacity and Modeling roadmap is outlined below in Table 2. There are four key areas that this roadmap focuses on:

- Continuing to evolve analytical and modeling capabilities within CYME
- Enhance scenario forecasting and integrate analytical capabilities
- Improve accuracy and update cadence for Hosting Capacity
- Continued automation and data enhancement

Table 2: 2025 - 2028+ Hosting Capacity Roadmap

	Short-term (2025)	Mid-Term (2026-2027)	Long-term (2028+)
CYME	• Establish Load Model Database • Establish Substation Model Database	• Integrate AMI into distribution models. • Automate Distribution Analyses	• 5-year Distribution System Model • Secondary system modeling • Downtown network modeling
Forecasting Enhancements	• Export CYME Connectivity model to LoadSEER	• Integrate LoadSEER into Load Model Database	• Increase forecast scenarios and include more growth vectors
Hosting Capacity	• Automate and streamline HCA process. • Implement quarterly HCA	• Implement monthly HCA • Leverage HCA to support internal processes (i.e. capacity check, interconnection)	• Continued automation and more frequent cadences • Validate HCA results against interconnection study results. • Integrate queued generation
Data Enhancements and Automation	• Advanced SCADA and data cleaning capabilities	• 8760 Analysis • Automate interconnection study process. • Export Scenario Forecasts into Load Model Database	• Continued Automation and Model Enhancements • Dynamic DER Operation Analysis

VI. DISTRIBUTION SYSTEM LOAD FORECASTING

HISTORICAL FORECASTING METHODOLOGY AND TOOLS

The planning and forecasting of the distribution system has evolved significantly since the Company's inaugural Distribution System Plan in 2022. The forecast provided in the 2022 Distribution System Plan was generated using a legacy planning tool, Itron's Distribution Asset Analytics ("DAA"). This tool had limited functionality relative to the suite of modeling and analytical software packages available today. DAA limited Planners to forecast distribution system capacity based on a single peak load value. Any new load growth was assumed to be coincident with this peak demand, and future growth could only be applied as a fixed percentage multiplier.

These forecasts were deterministic, in that a single growth scenario was developed and evaluated for system planning without consideration of other potentials for growth. This approach has been effective in years past where load growth was modest and relatively homogeneous. As adoption of building and transportation electrification and other DER technologies are increasing, this methodology is no longer adequate to plan the grid of the future. While the Company contracted with ICF Consulting to develop locationally specific forecasts of DER adoption in the 2022 Distribution System Plan, those forecasts were not used for planning distribution system investments in that Distribution System Plan. However, the Company has since migrated to a planning process that leverages the capabilities of LoadSEER to include forecasted DER adoption as discussed below.[17]

DISTRIBUTION SYSTEM FORECASTING EVOLUTION

The Company recognizes that the forecasting and planning of the distribution system needs to evolve to meet the needs of customers who wish to adopt these technologies. Over the past three years, the Company has increased the level of sophistication of its distribution planning forecasting process, outlined in Figure 11 to be better prepared to serve new expectations on the distribution system.

[17] As a result of the Company proactively moving forward with the LoadSEER forecasting, we did not validate the ICF forecasts, as the LoadSEER methodology uses an approach that would have little relationship to the ICF methodology.

Figure 11: Evolution of Distribution System Forecasting[18]

	Prior to 2021	2021 to 2022	2023 to 2024
Forecasting Methodology	Reactive & Deterministic	Reactive, Deterministic & Probabilistic	Proactive & Probabilistic
Temporal Considerations	Peak Hour per Asset & Growth Coincident with Peak	Time-Series TLY Curves (8760) & Load Curves	Time-Series TLY Curves (8760) & Load Curves
Forecasting Adoption	Applied Fixed Growth Rate	Spatial Allocation & Propensity Modeling	Spatial Allocation & Propensity Modeling
Growth Vectors	Service Applications	Service Applications & Customer Growth Forecast	Service Applications, Customer Growth Forecast, Clean Heat Plus BE, EV Growth, BTM PV
Planning Scenarios[1]	Single Scenario	Single Scenario	Two Scenarios
Forecasting Tools	Itron's Distribution Asset Analytics (DAA)	Integral Analytics' LoadSEER	Integral Analytics' LoadSEER

In 2021, the Company started implementing the LoadSEER forecasting software developed by Integral Analytics. LoadSEER is a spatial forecasting tool used by electric distribution system planners to predict how much power must be delivered, where on the grid the power is needed, and when it must be supplied. It integrates geospatial data, system and customer level data, historical and forecasted weather patterns, as well as distribution load flow application data, to produce a time-series forecast for every hour for each year of the forecast. Whereas the Company's previous load forecasting tool only allowed us to understand and plan to a single peak value, LoadSEER allows us to understand the loading patterns on distribution equipment for all 8760 hours of the year.

The implementation of LoadSEER has enabled the Company to develop scenario forecasts to evaluate how varying adoption rates for different technologies impact the distribution system and where capacity upgrades are required.

In the first two years of deploying LoadSEER, the Company's Distribution System Planning team continued to produce a single, deterministic forecast[19] as the team gained experience in some of the more critical, advanced, and complex functionality within the platform. These first two forecasts leveraged LoadSEER's Spatial Allocation tool in addition to developing propensity modeling for customer adoption. These tools allow for

[18] This figure depicts the two LoadSEER forecasts submitted in this Plan but does not represent the additional scenario analysis performed by the Company and Kevala, which is discussed further below.
[19] This does not include the two Scenario Forecasts developed in the inaugural Distribution System Plan filing in 2022. Those were produced outside of the internal forecasting process and were not used in the planning of the distribution system.

the stochastic allocation of Operating Company level forecasts down to the premise level while accounting for customer propensity for adoption. Another key advancement was the shift from forecasting to a single peak value to generating a time-series forecast that accounts for the time-varying nature of different types of demands using load curves. Load forecasts are now generated on an 8760 curve, meaning a single datapoint for each hour of the year for each year of the forecast. Growth is layered onto these 8760 curves using load curves that depict the hourly load impacts of each technology type. These advancements have continued to be built upon in preparation for this filing.

Figure 12: Key Recent Improvements to Distribution System Load Forecasting Process

- Proactive planning to prepare the distribution system for decarbonization
- Development of time-series forecasts
- Scenario forecasts used to plan the distribution system
- Alignment of planning forecasts with state and local goals and policies

CURRENT STATE OF DISTRIBUTION LOAD FORECASTING

Over the past year, Distribution Planning has been building upon the previous advancements in forecasting in preparation for this filing. The Distribution Planning team has generated two scenario forecasts used in the planning of the distribution system. This is the first time that Distribution Planning has utilized multiple forecasts in the planning of the distribution system and marks a pivotal change in how the Company is forecasting and planning for the grid of the future. Each forecast serves a specific purpose and allows Planning to consider different scenarios when evaluating the system. These scenarios are discussed in more detail in this section.

FUTURE STATE OF DISTRIBUTION SYSTEM FORECASTING

As described previously, the Company has made significant strides in advancing how it forecasts and plans the distribution system. This evolution will continue throughout this energy transition, and the Company sees four key areas as the next stage in this process, as shown in Figure 13.

Figure 13: Key Areas to Continue Forecasting Evolution



Partner with Municipalities, Cities and Stakeholders

Forecasting is becoming increasingly complex and can no longer be performed in a vacuum. These four areas allow the two-way flow of information between stakeholders and the Company to improve assumptions and propensity modeling and adoption trends, but also create opportunities to align infrastructure projects to minimize disruptions to communities as we are building out the distribution system. While it will never be possible to perfectly align on everything, this would provide stakeholders and the Company the opportunity to share long-range development plans and coordinate development. For example, municipalities and the Company can coordinate underground feeder extensions and road resurfacing to minimize impacts in an attempt to avoid paying for the same scope of work more than once. This will help to keep costs down for all parties involved to help ensure the transition is affordable for all customers.

This also provides stakeholders with an opportunity to share their future to help influence how the Company plans the future distribution system. Some examples are including DER protection upgrades as part of new substation upgrades knowing long-term interest in specific areas, or long-term oil and gas electrification in remote areas.

Alignment with State and Local Goals

By establishing a process by which stakeholders can share plans and interest with the Company, the Company will be in a better position to ensure that their forecasts and capital plans align with local and state decarbonization goals. The Company wants local municipalities to be successful in their goals, and working together helps to achieve this future state. Evaluating different scenarios around these goals will help the Company to prepare for different outcomes and helps ensure today's investments are prudent and align with the long-term needs.

Tool and Data Enhancements

The Company is enhancing its modeling and analytical capabilities to help facilitate more sophisticated forecasting methodologies and the ability to better study the impacts the distribution system. These tools, which are discussed in more detail in Section X, will create a foundation by which the Company can better evaluate different scenario forecasts to better inform near-term investment. These tools enable the Company to better streamline, and even automate, some distribution studies and engineering processes, including, but not limited to:

- Additional Scenario Forecast Development
- Load and Generation Interconnection Studies
- Load and Generation Hosting Capacity Analysis
- 8760 and Scenario Forecast Load Flow Analysis
- Bulk Distribution System Studies

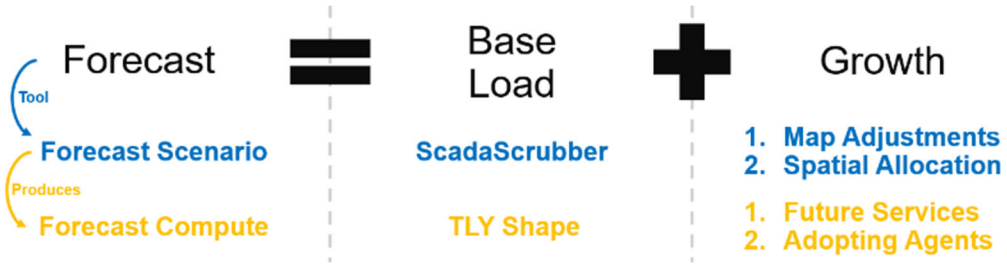
Expand Company Expertise

The Company has made significant strides in advancing its forecasting methodology. The lessons learned and insights gained from this effort will influence how we continue to progress along this evolution. Building upon this expertise will help us to better understand our customers and their needs through AMI data, increased communication and more transparency. Building this relationship and expanding our in-house expertise will ensure that we are good stewards for the communities we have the privilege of serving.

LOADSEER FORECASTING METHODOLOGY

The methodology outlined in this section is what was used to generate the scenario forecasts leveraged by Distribution Planning to plan the distribution system. The assumptions and detailed methodology used to generate these forecasts were developed into a technical appendix, which can be found in Attachment DCM-9. The methodology can be illustrated by a generalized formula in Figure 14.

Figure 14: Forecast Formula

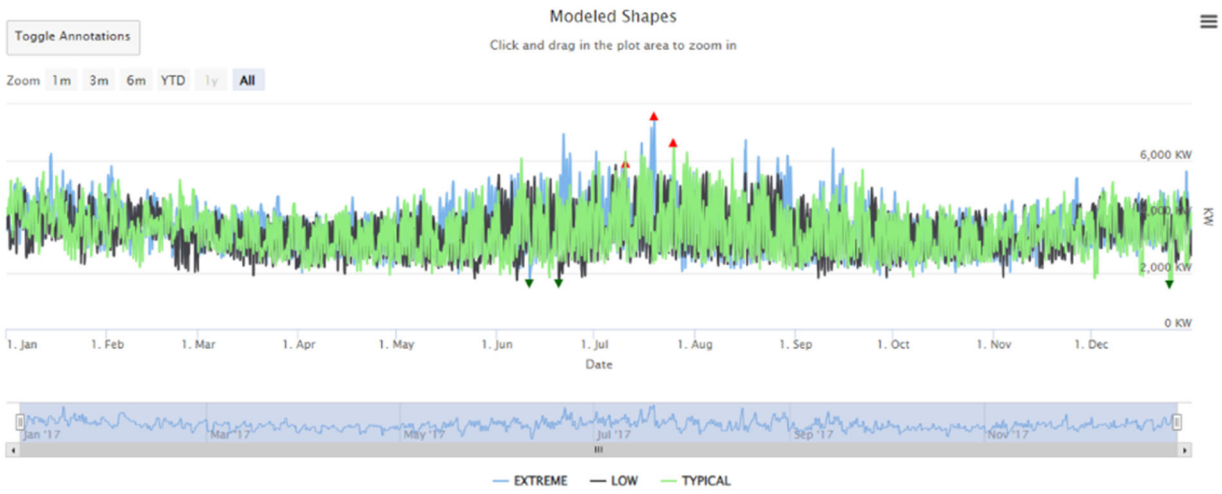


The forecast consists of two main components, which involve constructing a base load forecast and then modeling a growth propensity.

The base load is compiled using a LoadSEER tool called SCADAScrubber. The primary function of this tool is to develop Typical Load Year ("TLY") shapes, which represent the load on the circuit today under different weather scenarios. The TLYs are 8760 load shapes, meaning that they represent the hourly loading on the feeder throughout a full year. Whereas previously, our load forecasting tools were limited to assessing single peak values, the TLY analytical feature of LoadSEER allows us to understand loading across all hours of the year.

Users of SCADAScrubber have the ability to clean historical SCADA data, which eliminates any operational switching impacts as well as any other anomalous data that could confound the risk assessment process. SCADAScrubber load and weather-normalizes the SCADA data before re-simulating it against a low, typical, and extreme weather scenario to produce the TLY shape. The tool does this by assembling 30 years of hourly historical weather datasets that are available at the weather station closest to the feeder or substation transformer being analyzed. Once a TLY has been produced, as shown below in Figure 15, it then can be imported into LoadSEER for inclusion in a load forecast.

Figure 15: LoadSEER - Typical Load Year Example



Once a TLY has been created to represent the base load, load growth in the forecast is then accounted for via map adjustments and spatial allocation.

Map adjustments are primarily used to represent known load growth in the load forecast. When a customer applies to interconnect load to our distribution system or requests a capacity check, a map adjustment can be used to account for that added load at the corresponding geographic location in the LoadSEER model. When a map adjustment is added, a load shape that represents the expected hourly demand of that customer is also identified in LoadSEER. This is helpful for distribution planning because the customer's peak demand is not always coincident with the feeder or substation transformer peak demand, so using load shapes for map adjustments enables a more accurate capacity check process than was possible prior to the LoadSEER implementation.

Map adjustments can also be used to flag areas where the Company anticipates there to be higher levels of adoption of a particular technology. For example, if a strip mall has reached out to the Company to inquire about adding EV chargers at their parking lot but is not ready to install for several more years, a map adjustment for the potential of that load addition can still be added. But rather than "locking" the map adjustment, which effectively guarantees that the load will be included in the forecast, it would instead have a representative probability of adoption that is fed as an input into the Spatial Allocation. These conceptual future potential map adjustments can assist in increasing the accuracy of the forecast by focusing the load growth to geographic areas with a higher propensity of adoption of a particular technology.

Whereas map adjustments are manually added to the LoadSEER model by the Company, Spatial Allocation is generally done in collaboration with Integral Analytics, the developer of LoadSEER. Spatial Allocation is a significantly more intelligent and automated

approach to simulating load growth across the distribution system than map adjustments. However, having both map adjustments and Spatial Allocation work in conjunction with each other significantly increases forecast accuracy, so both are necessary.

The concept of Spatial Allocation can be summarized into a generalized formula as shown in Figure 16 below.

Figure 16: Spatial Allocation Formula



The key function of Spatial Allocation is to simulate load growth across the system via a probabilistic model that determines likely technology adopters. It takes a forecast that is typically at a high-level node in the asset hierarchy, like state or operating company, and then disaggregates that forecast intelligently to existing and future customers at specific locations on the distribution system. The Company provides LoadSEER with a forecast and shape for a particular technology as inputs for the Spatial Allocation. The Company then collaborates with Integral Analytics to identify future potential adoption points relevant to the forecast supplied. During this process, the goal is to guide Integral Analytics to indicate which data services to target, supply any relevant external data sets, and supply internal information regarding high adoption areas.

Shapes in LoadSEER provide an hourly estimation of customer loads for a particular technology or customer type. These shapes are developed using both internal data sets and industry collaborations with institutions, such as NREL and EPRI. As AMI interval data becomes more readily available, the Company anticipates that these shapes will improve in accuracy. These shapes are used in LoadSEER for map adjustments, Spatial Allocation, and the forecast as a whole.

Growth can come from a variety of different factors, including new customers being interconnected with the distribution system, changes in customer usage patterns, and the adoption of different DER technologies such as solar PV, electric vehicles, and more. To address this, each type of growth is allocated in a unique run of the Spatial Allocation that is designed to target and model the adoption of that specific type of growth or technology. To compute a load forecast, Distribution Planners can select any individual or combination of Spatial Allocation runs to add to the base load TLY shapes. This allows the Company to either isolate a particular growth factor to understand how it is individually

affecting distribution system loading or merge multiple growth factors together to see the aggregate net impact that a variety of technologies will have in the long term.

LOADSEER DISTRIBUTION FORECAST SCENARIO PLANNING

Internally, the Company has developed two scenario forecasts to support distribution planning. Each forecast serves a unique purpose in the planning of the distribution system. Technical assumptions used in the development of this forecast can be found in Attachment DCM-9: Technical Appendix.

Capacity Check Forecast

The Capacity Check Forecast contains the base load TLY, and the known growth approved by Distribution Planning through the formal capacity check process for new or upgraded electric service requests. By only capturing known growth on the system, this forecast is used by Planners when evaluating new capacity checks for new or upgraded distribution services. As new growth is approved, the Capacity Check Forecast is refreshed to reflect the updated available capacity to ensure accurate results for customers.

Base Forecast

The Base Forecast is used by Planners to evaluate the short-term and long-term capacity needs for the distribution system. In addition to accounting for the base TLY and the known capacity check growth, other growth vectors were applied to the Base Forecast to prepare the grid for the adoption of new technologies that are not ready to apply for service. This forecast includes the known growth included in the capacity check forecast, but also includes growth based on the Company's corporate energy sales forecast as well as forecasted adoption of beneficial electrification demand, electric vehicle demand and behind-the-meter solar PV growth. A comparison table of the Capacity Check Forecast vs. the Base Forecast is provided below.

Table 3: Comparison of Capacity Check Forecast to Base Forecast

Forecasted Growth Vectors	Capacity Check Forecast	Base Forecast
Known Growth	Yes	Yes
Sales Growth	No	Yes
DER and Technology Adoption	No	Yes

The growth vectors listed below were applied to the Base Forecast in addition to the Map Adjustments recorded in LoadSEER by the Planning team as a part of the Capacity Check process.

Behind-the-meter ("BTM") Solar – the Company's forecast of BTM solar forecasts future solar PV installations based on recent trends in installations and applications in the

near-term and on a bass diffusion model in the long-term. The associated peak and sales impacts are then derived from typical system size and performance. The DSP filing forecast uses the base case solar forecast developed in June 2023.

Demand Side Management ("DSM") – the Company's forecast of energy efficiency and demand response measures is based on the Company's approved DSM plans. The impact of historical efficiency programs, and their ultimate replacement by overarching efficiency trends, are embedded within the base customer growth forecast described below. Future efficiency programs are defined separately and apply load shapes designed to reflect the specific technologies impacted by each program.

Electric Vehicles – the Company's EV forecast is developed based on the combination of a total cost of ownership and bass diffusion model updated on an annual basis. This forecast projects future EV purchases by state, deriving peak and sales impacts from expected charging loads over time and assumptions around the distribution between managed and unmanaged patterns. The DSP filing forecast uses the high case forecast developed in June 2023.

Beneficial Electrification – the Company's beneficial electrification forecast was developed based on an adaptation of the Amended Preferred Portfolio in the CHP proceeding through 2030. Impacts are then extrapolated to the end of the forecast period based on appliance saturation trends. At the time this forecast was developed, the CHP proceeding had not been finalized. Due to ongoing efforts to integrate beneficial electrification programs into the forecast and reconcile them with existing programs, this initial adaptation did not incorporate the near-term impacts of the Strategic Issues filing as was used in subsequent forecasts in 2024. The DSP filing forecast uses a standalone adaptation of the CHP APP developed in January 2024.

Base Customer Growth Forecast – The Company develops its base Growth Forecast using a series of models translating customer growth into sales growth and ultimately into peak demand. These models rely primarily on historical values for all three outputs, along with historical and forecasted economic and demographic data from IHS Markit and CoStar.

These forecasts begin with an outlook for customer counts by rate class developed based on regression models of historical customer counts against econometric data including population and multi-family housing additions.

Sales outlooks are developed either as a use per customer forecast, for Residential, or a total sales volume forecast, for Commercial and Industrial. In both cases, the Company uses a Statistically Adjusted End-Use ("SAE") modeling approach. The SAE method entails specifying energy use as a function of the primary end-use variables (heating,

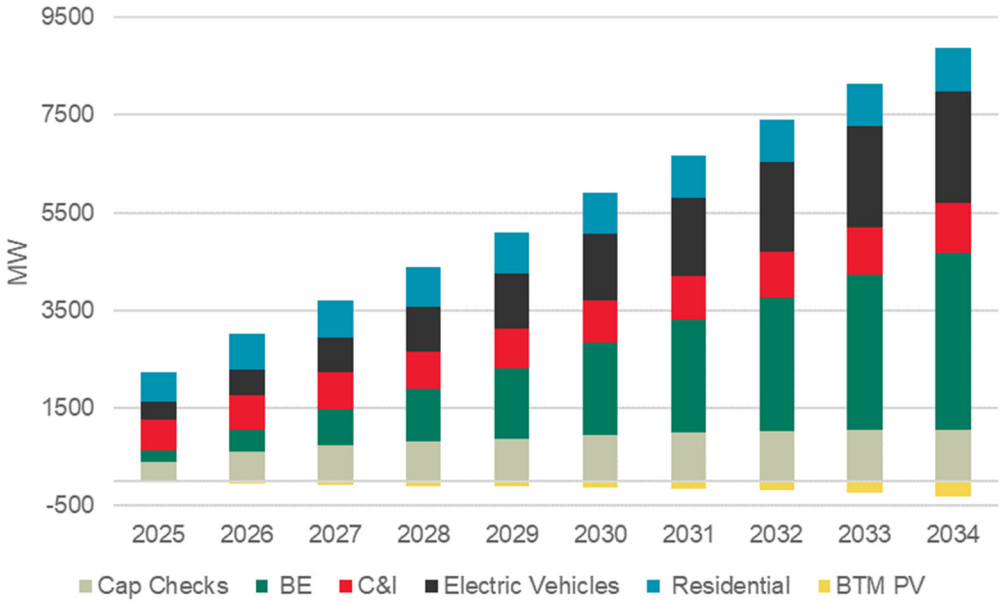
cooling, and base use) and the factors that affect these end-use energy requirements. This includes saturation, efficiency, and utilization of different appliances over time. Saturation assumptions are derived from the Company's Home Use survey for Residential models and Energy Information Administration ("EIA") data for Commercial and Industrial models. Efficiency assumptions are provided by the EIA entirely, while utilization is derived from weather and economic data. Notably, heating electrification is accounted for separately as noted above, and so forecasts assume static appliance saturation for heating.

Peak forecasts are based on historical uninterrupted native coincident peak demand by the Residential and Non-Residential customer classes, meaning the effects of demand response and behind-the-meter solar generation are removed from the historical data. These values are then regressed against the sales by each customer class and weather. The baseline customer growth defined here as the Base Customer Growth Forecast is then derived from the year-over-year increase in peaks by class, with incremental customer additions determined based on an assumption of a typical peak addition per customer. This approach results in a disconnect between the number of customer additions assumed from the beginning of the process to the end, but pointedly aligns the peak additions.

BASE FORECAST RESULTS

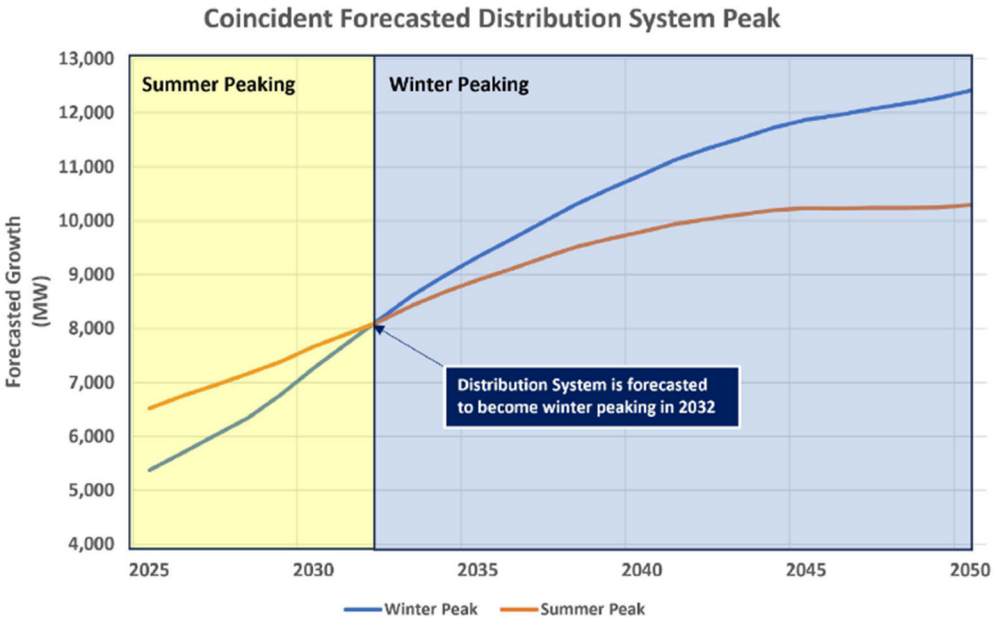
The inclusion of the load modifying impacts of forecasted DER adoption results in a significant increase in demand on the distribution system. The non-coincident nameplate growth from both known load growth (capacity checks) and the growth from the spatial allocations are broken down in Figure 17.

Figure 17: Non-Coincident Cumulative Forecasted Demand (MW)



The total non-coincident growth in the 10-year distribution Base Forecast is over 8.8 GW, largely driven by the impact of projected beneficial electrification and electric vehicle adoption. To determine the coincident forecasted peak demand, Distribution Planning aggregated typical load year ("TLY") curves for all substation banks to produce a coincident PSCo distribution system peak load curve. The summer and winter peaks were extrapolated over the full 30-year forecast to determine the long-term growth trends and to identify when the system is expected to transition from summer peaking to winter peaking. The Base Forecast scenario anticipates that this transition will occur in 2032 as indicated by Figure 18.

Figure 18: Distribution System Peak Transition from Summer Peaking to Winter Peaking



The coincident distribution system peak is expected to more than double by 2050, increase from approximately 6.1 GW in the summer of 2025 to over 12.6 GW in the winter of 2050.[20] While this DSP focused on the 10-year forecast through 2034, this long-range view is helping to inform longer range integrated system planning to ensure the short-term action plan reflected by this Plan aligns with the long-term grid vision.

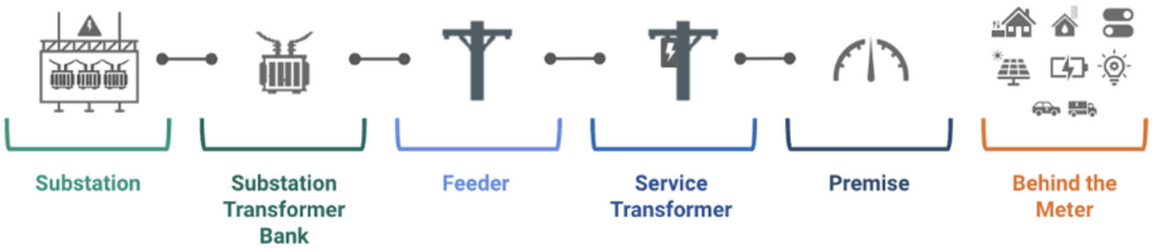
The impacts and the project portfolio identified from the Base Forecast are detailed in Section VII.

[20] The coincident distribution system peaks reflected here do not include load and demand on the bulk system (e.g. transmission connected loads or wholesale customers).

ADDITIONAL SCENARIO MODELING

In addition to the Capacity Check and Base Forecasts developed by the Company using LoadSEER, the Company commissioned Kevala to conduct long term-analysis for four scenarios as detailed in Appendix 1. The Company also worked with Kevala to develop and model two sensitivities designed to test the hypotheses that additional load flexibility targeted at reducing loading on distribution system assets may mitigate future infrastructure needs. Kevala's analysis and report included developing a base forecast, locationally specific adoption forecasts of DERs that were applied to the base forecast, as well as estimates of necessary grid reinforcements corresponding to the load forecast for each scenario. At a high-level, the methodologies employed by the Company's Distribution Planning organization and Kevala are similar in that both forecasting methodologies use the concept of customer technology adoption propensity to develop granular, locationally specific (i.e. premise level) load forecasts. These premise-level forecasts are then further combined based on the Company's network topology and connectivity to develop asset specific load forecasts for the entirety of the distribution system. A simplified version of that asset hierarchy is presented in Figure 19 below:

Figure 19: Distribution System Asset Hierarchy



It is important to note that the infrastructure estimates that were developed as part of the Kevala analysis are high-level indicators of infrastructure needs and do not take the place of the detailed engineering analysis that the Company's Distribution System Planning team conducts annually. Additionally, it is also important to note that estimates[21] only represent capacity investments, and do not represent the costs of other distribution system budget categories such as Asset Health & Reliability. Nevertheless, the modeling performed by Kevala allowed the Company to explore additional scenarios as well as assess the potential impact of load flexibility programs on required distribution system capacity investments through 2050.

A summary of the scenarios modeled by Kevala are reflected in table below and the full Kevala report is reflected as Appendix 1 to the Plan.

21

Table 4: Kevala Forecast Scenarios

Scenario Name	Description
Calibration	• Meets load growth in line with the current DSP (Base Forecast). • Uses assumptions and inputs currently being leveraged by the Company planning team in their 2023/2024 LoadSEER run
Policy Aligned	• Meets load growth associated with all updated Colorado state and local binding policies / mandates. • Leverages current Company forecasts, and updates numbers to include most recent policies & mandates (e.g., Energize Denver, Boulder gas ban, impact of IRA on MDEV adoption, etc.)
Goal Aligned	• Includes growth to meet Colorado state and municipal decarbonization goals through 2050. • Uses data extracted from State's decarbonization study with municipal goals from Denver & Boulder layered on (e.g., local GHG targets, etc.)
Adoption Informed	• Provides forecasted adoption trajectories founded in historical adoption rates for specific and related technologies modified by the Company's perspective. • Starts with customer adoption data, and extrapolations developed through 2050 with 3rd party forecasts, market insights, and external data used to benchmark

Figure 20: Overview of Policy and Goal Information Used in Scenario Analysis



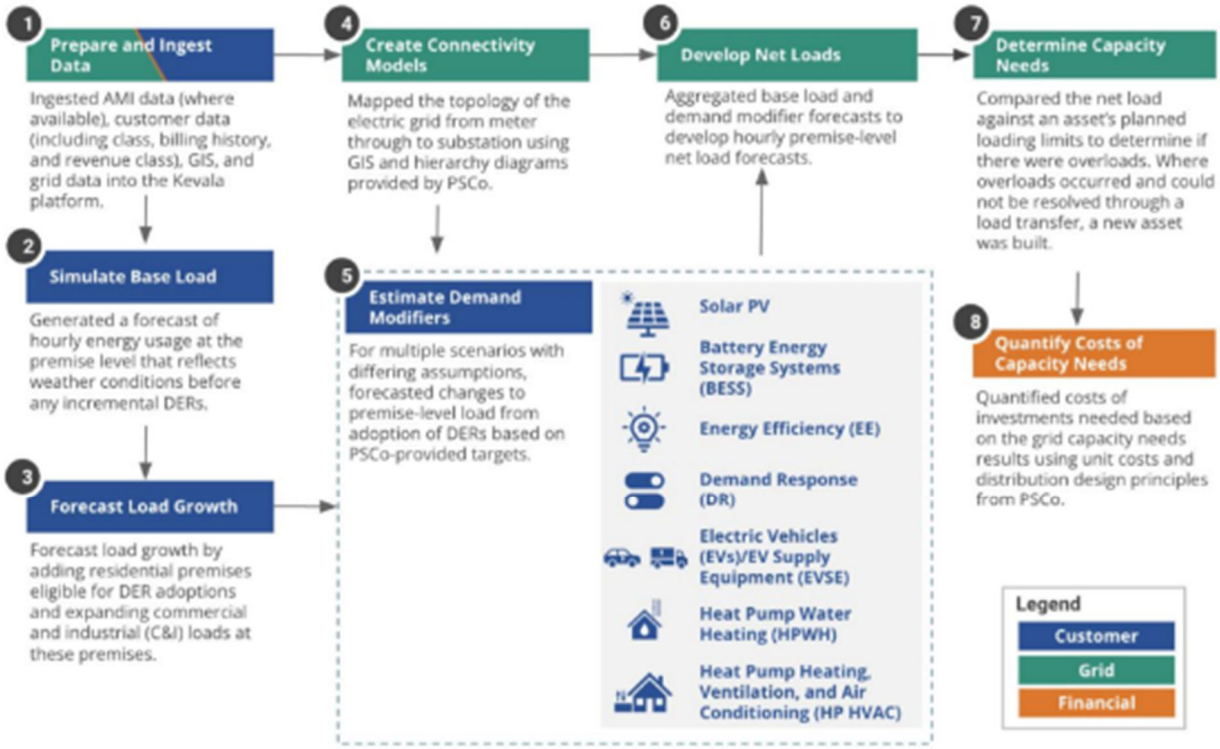
Methodology

Kevala's methodology relied on a combination of Company data and third-party information. The primary source data provided by the Company included interval meter data, customer billing history, GIS and related connectivity data amongst other sources. This initial information was used to simulate a baseload forecast as indicated by Step 2 in Figure 21 below. The Company worked closely with Kevala to align the initial year of the baseload forecast to ensure that the starting conditions and assumptions were similar across both the LoadSEER and Kevala methodologies. Next, forecasted load growth for all scenarios was applied against the baseload to develop a forecast of net load for each scenario– inclusive of the load modifying impacts of DERs. Each scenario specific net load forecast was modeled at the premise-level with hourly granularity.

Determination of Capacity Needs

For each scenario, Kevala compared the net load forecast against an asset's planned loading limits. In instances where the net load forecast would result in an overload, Kevala attempted to first mitigate the overload by determining if adjacent assets had sufficient capacity to accommodate a load transfer as indicated by step 7 in the below diagram.

Figure 21: Summary of Kevala Electrification Impact Model



If a load transfer could not resolve the overload, Kevala's model recorded the need to build a new asset.

Key Findings of the Kevala Analysis

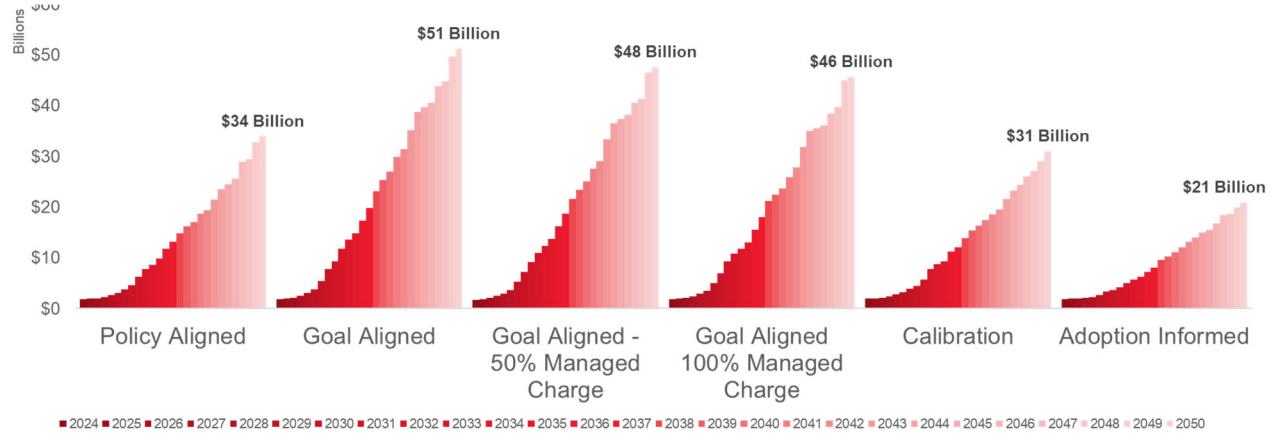
The four scenarios modeled, and two load flexibility scenarios, provide insight into what the future of the system could look like in Colorado. Notably, to meet either the binding policy goals that exist today or the state's policy goals, it will require significant investment in new grid infrastructure to serve capacity. Collectively, these scenarios suggest that the grid will need to be expanded roughly 2-3x its current size.

Table 5: Cumulative, Incremental Distribution Infrastructure Required through 2050

	Feeders	Substation Banks	Substations
Adoption Informed	724	158	83
Policy Aligned	1215	253	118
Goal Aligned	1918	396	170
Goal Aligned – 50% Managed Charge	1780	369	161
Goal Aligned – 100% Managed Charge	1715	357	155
Calibration	1083	231	107

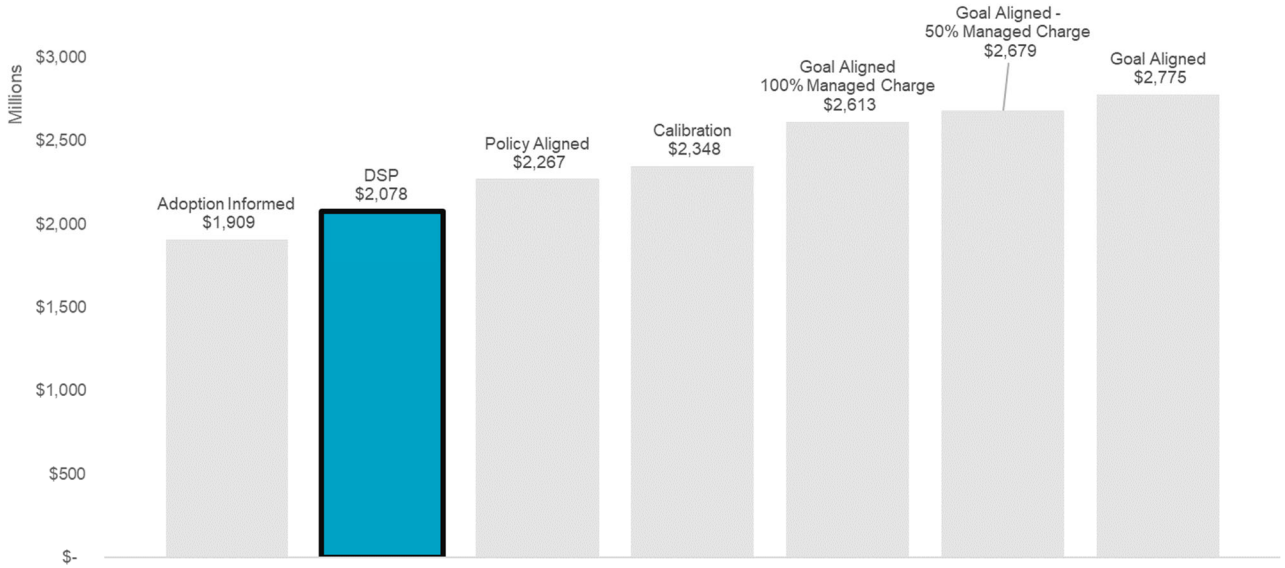
From a cost perspective, the Kevala analysis indicates that there are a wide variety of potential outcomes in terms of cumulative costs through 2050 related to distribution system capacity investments ranging from $21 billion - $51 billion over that same time period. The Company also worked with Kevala to model the potential impacts of load flexibility targeted specifically at reducing distribution infrastructure needs on the most aggressive DER adoption scenario (Goal Aligned). The methodology is further detailed in Appendix 1 to this Plan document. The impact of additional flexibility indicates a potential cost reduction of $3 billion to $5 billion by 2050 due to the impact of managed charging as demonstrated by Figure 22. Importantly, the trajectory of cost impacts across all scenarios is similar through 2029.

Figure 22: Distribution System Cumulative Capacity Investments



The Company also compared the Kevala modeling results to the investment levels reflected in the Company's 2025-2029 Distribution System Capacity budget (reflected by the blue bar chart on Figure 23 below). Relative to the Kevala scenarios, the Company's budget is in a range of reasonableness.

Figure 23: Comparison of the Company's Five-Year Capacity Budget to the Kevala Scenario Modeling[22]



[22] The Kevala model also includes 2024 capacity estimates.

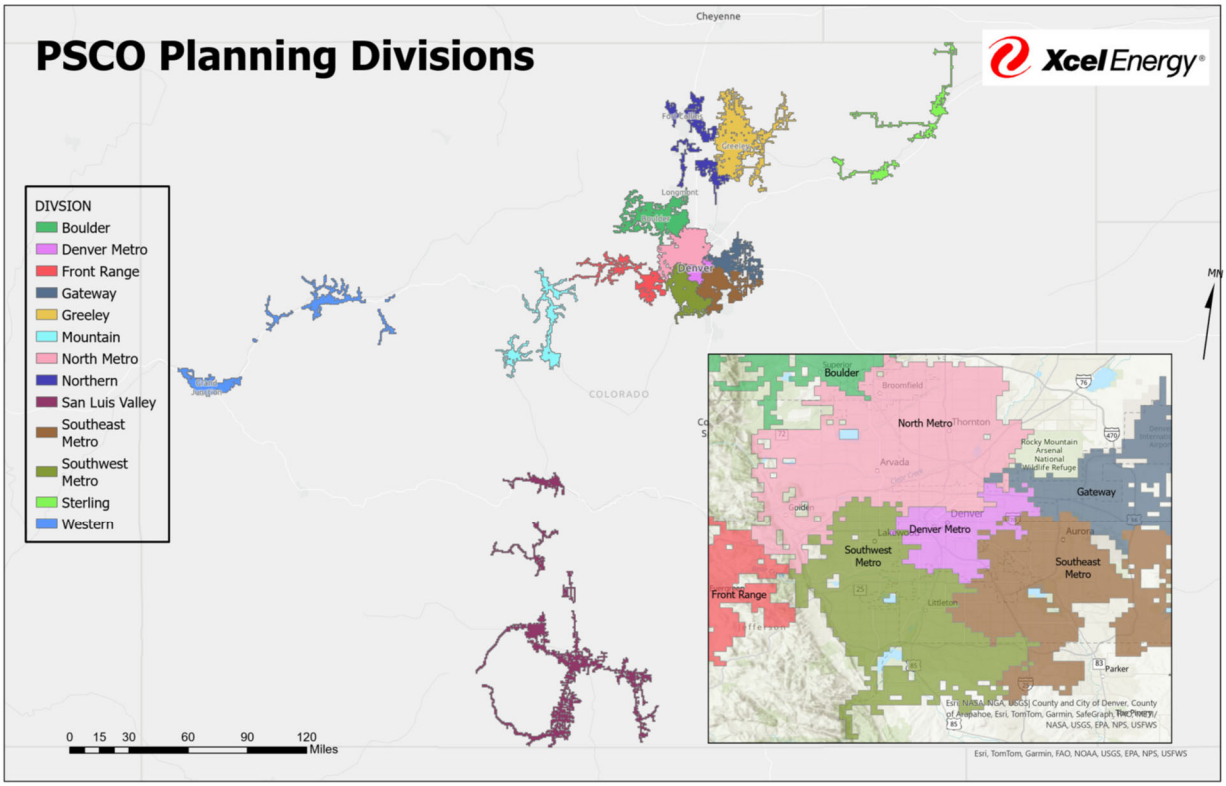
VII. GRID NEEDS ASSESSMENT

SYSTEM OVERVIEW

Public Service operates, plans, and maintains a distribution system that provides electricity to over 1.6 million customers in Colorado. The electric distribution system includes assets in 25 counties throughout Colorado and provides electric service to both rural and urban customers. The distribution system consists of approximately 152 distribution-level substations that support a network of over 800 distribution feeders necessary to serve our customers. These distribution feeders include approximately 9,500-line miles of overhead distribution lines, 14,500-line miles of underground distribution lines, and over 585,550 poles.

Distribution System Planners divide the distribution system into thirteen divisions, outlined in Figure 24. A team of eight System Planners oversee the planning divisions and are responsible for overseeing the growth on the system through the capacity check process, support the generation of the distribution forecast and risk analysis, and develop the capacity projects needed to support the distribution system. Recognizing the significant increase in distribution planning work and the increasing complexity of the analysis, the Company's Staffing Analysis in this plan reflects an increase of about 117 full-time equivalents ("FTEs") commensurate with level of work and skillsets that will be required today and in the future. This includes hiring employees and contractors to perform an increasing volume of work as well new skillsets and capabilities to evaluate and implement non-traditional solutions such as NWAs, VPPs, and Flexible Interconnection.

Figure 24: Distribution System Planning Divisions

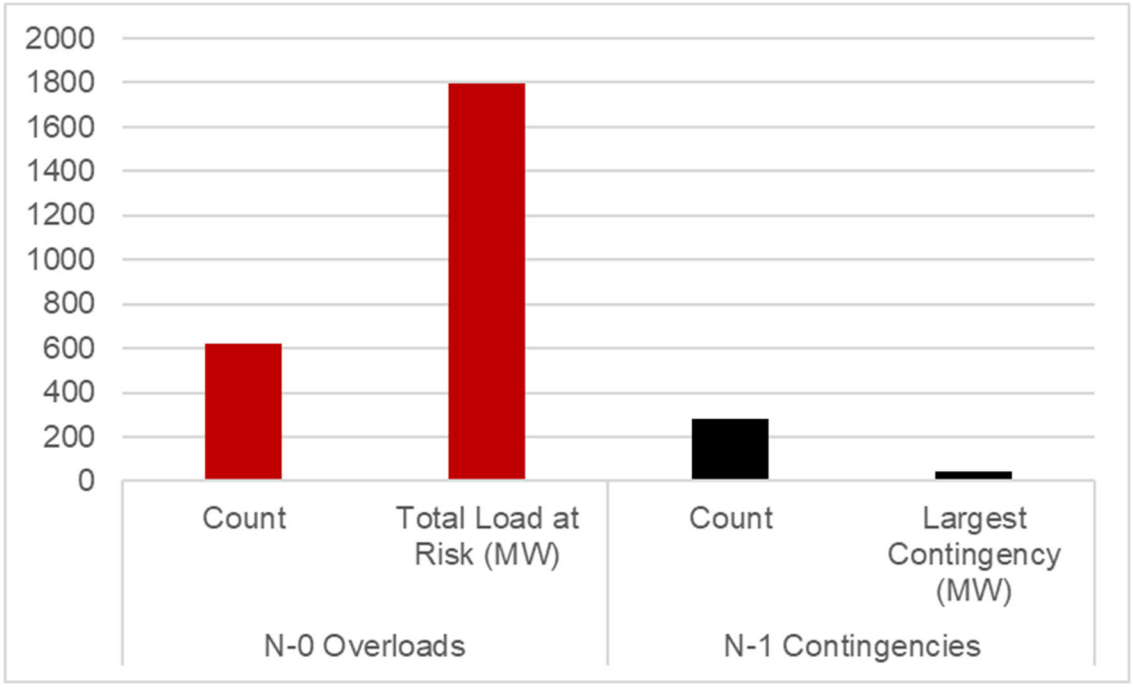


GRID NEEDS OVERVIEW

Distribution Planning conducts an annual risk analysis to inform system planning. The analysis of Grid Needs in this DSP uses the Distribution Base Forecast (inclusive of the load modifying impacts of DERs) as its primary risk assessment.

The resulting Grid Needs Assessment ("GNA") is a summary of N-0 Overloads and N-1 Contingency risks identified throughout the 2025-2034 forecast for distribution feeders and substation banks. This GNA in this Plan contains 901 distribution risks, up from 270 in the previous Distribution System Plan filing. A summary of the grid needs portfolio is provided in Figure 25.

Figure 25: 2025-2034 Aggregated Distribution System Risk Portfolio



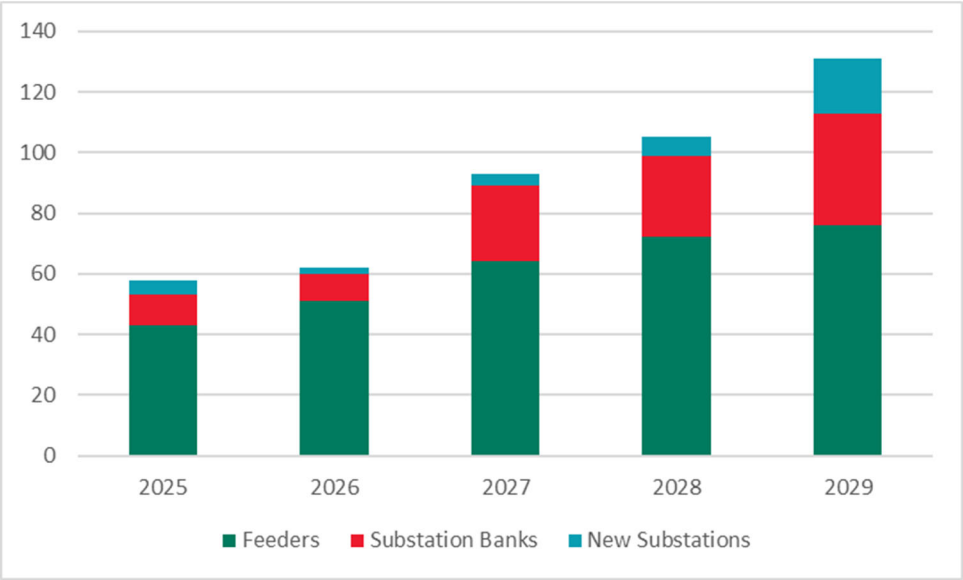
The increase in distribution system risks is the combination of two factors. First, the incorporation of the load modifying impacts of forecasted DER like electric vehicles and heat pumps results in significant additional load. The aggregate impact of this is most evident in Figure 25. Second, the Company has implemented an updated technical load planning standard of reducing utilization of feeders at or below 75% of the continuous rating. The planning standard is essential to maintain operational flexibility related to switching and reliability. Additionally, the planning utilization will also allow us to accommodate forecast deviation that is inherent to making forecasting decisions that attempt to forecast individual customer decisions at the premise level.

To mitigate these grid needs, Distribution Planning has developed 180 capacity projects, 145 of which are considered Major Distribution Grid Projects.[23] A capacity project typically consists of several discrete work tasks as defined by the Company's work order structure in its work ordering tracking system. For example, a capacity project could include installing a new substation transformer bank, extending multiple feeders from the substation transformer bank, and enabling communications to monitor the substation.

[23] "Major distribution grid project" means planned, proposed, or potential construction, reconfiguring, or upgrade of any electric distribution line, substation, or ancillary structure that meets the following criteria: (1) is a project estimated to require an investment of more than $2 million on the distribution grid or more than $3 million on both the transmission and distribution grids; and (2) will be made at or near an existing or planned substation, or feeders or transformers associated with a substation.

The portfolio of capacity projects is summarized in Figure 26.

Figure 26: Major Distribution Asset Deployment by Year



The following section presents the distribution risk portfolio, the capacity projects and the end-of-life replacement projects planned for the 5-year budget for each of the Company's 13 total planning divisions.

2025-2029 DISTRIBUTION DIVISIONAL PLANS

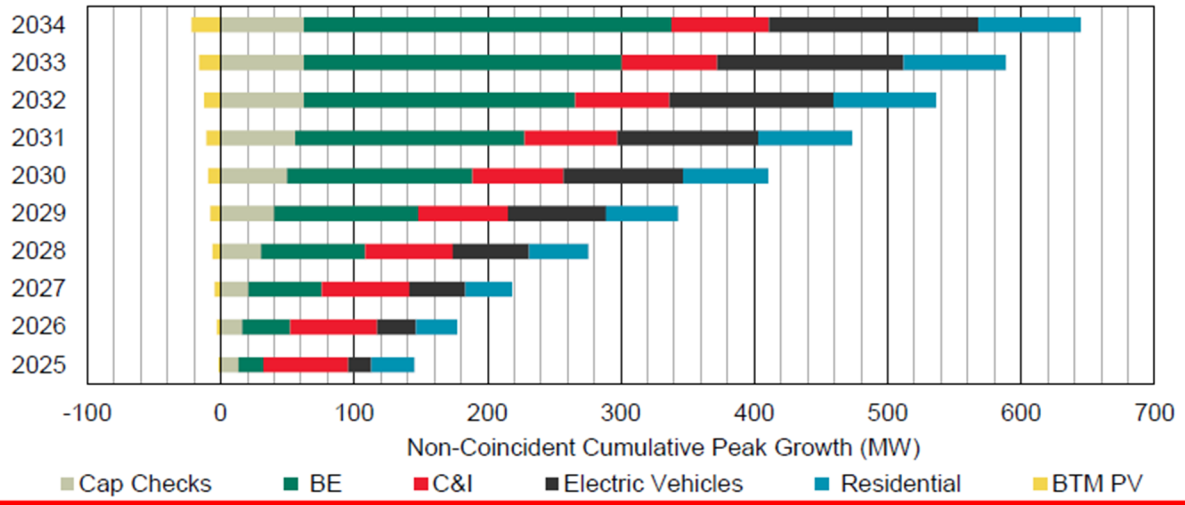
This section of the DSP outlines the forecasted growth, the distribution system risks and high-level capacity projects details for each of the 13 distribution planning divisions. These divisional plans provide more insights into the growth, risk profile and aggregated capacity project data. Specific projects can be found in Attachment DCM-2.

Boulder Planning Division

The distribution system supporting Boulder division consists of 10 substations, 18 substation transformers and 50 distribution feeders. The division spans approximately 481 square miles, from Broomfield up to Longmont and west to Nederland, outlined in Figure 24. The nominal distribution system voltage is primarily 13.2 kV with some 24.9 kV supporting the mountains west of Boulder.

The Company has seen moderate growth in Boulder, with approximately 99 MW of non-coincident known load growth approved by Distribution Planning through the formal capacity check process. Boulder's forecasted spatial allocation of DER adoption, shown in Figure 27, predicts over 580 MW of non-coincident growth and 22 MW of behind-the-meter solar PV. This has resulted in 44 N-0 overload and 11 N-1 contingency distribution risks. Distribution Planning has developed eight capacity projects to mitigate these system risks, which will add approximately 120 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the Boulder division. The major asset deployments and replacements are detailed in Figure 27.

Figure 27: Boulder Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	44	11	141	19

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	8	1	5	12

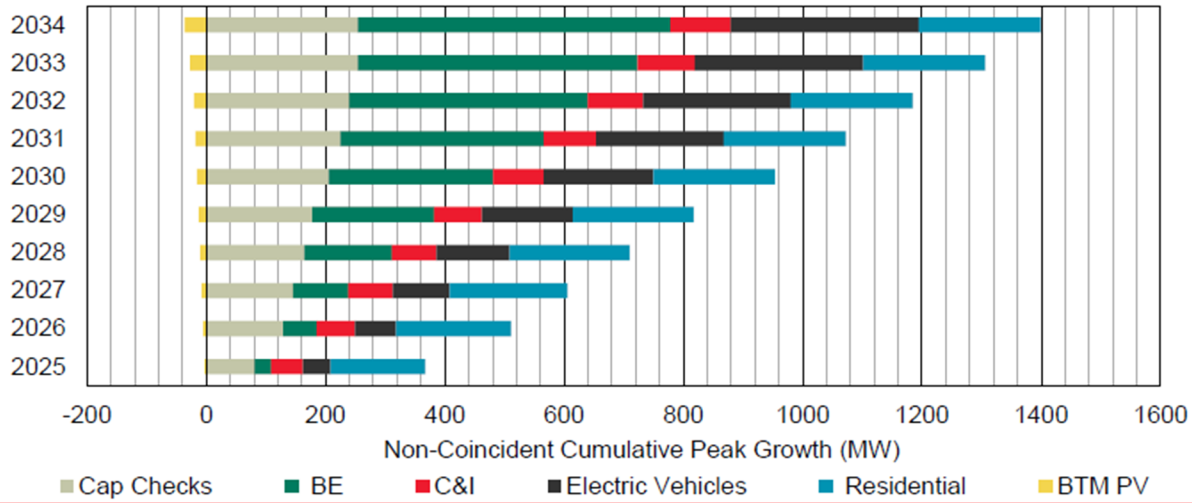
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
3	2	1	0	4

Denver Metro Planning Division

The distribution system supporting the Denver Metro division consists of 11 substations, 29 substation transformers and 119 distribution feeders. The division spans approximately 51 square miles, outlined in Figure 24. The distribution nominal distribution system voltage in Denver Metro is 13.2 kV. The Denver Metro system contains a downtown network system, which is a unique distribution construction relative to the rest of the PSCo distribution system.

The Company has seen significant growth in the Denver Metro, with approximately 315 MW of non-coincident capacity check demand approved. The Denver Metro division's forecasted spatial allocation, shown in Figure 28, predicts over 1.15 GW of non-coincident growth and 37 MW of behind-the-meter solar PV. This has resulted in 79 N-0 overloads and 17 N-1 contingency distribution risks. Distribution Planning has developed 25 capacity projects to mitigate these risks, which will add approximately 750 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the Denver Metro division. The major asset deployments and replacements are detailed in Figure 28.

Figure 28: Denver Metro Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	79	17	263	32

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	25	9	24	74

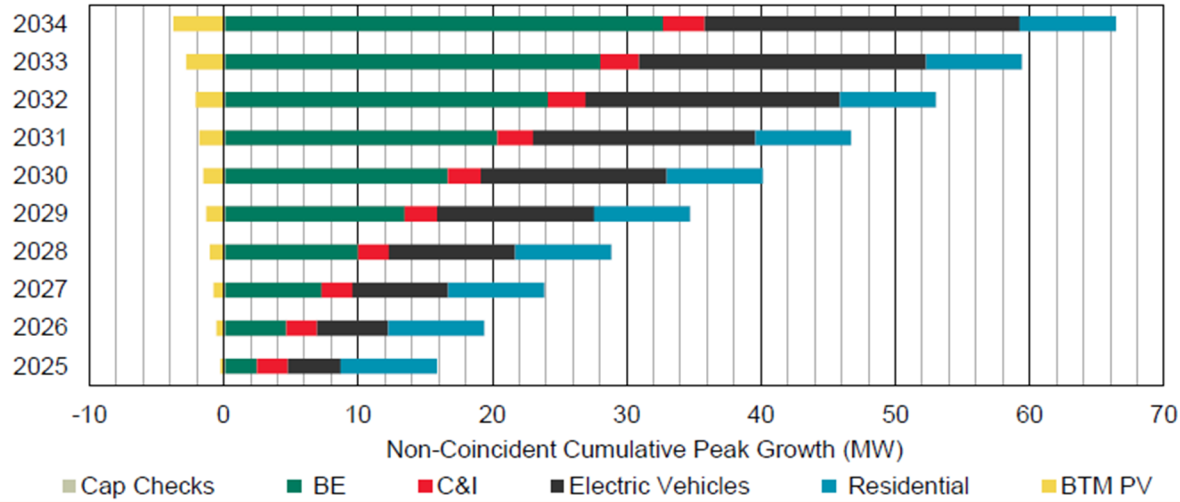
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
1	1	0	0	1

Front Range Planning Division

The distribution system supporting the Front Range division consists of 6 substations, 8 substation transformers and 15 distribution feeders. The division spans approximately 313 square miles and includes Golden to Georgetown, shown in Figure 24. The nominal distribution system voltage is primarily 24.9 kV, with some 13.2 kV sections of the distribution system.

The Company has seen little growth in the Front Range, with approximately 0.6 MW of non-coincident capacity check demand approved. The Front Range division's forecasted spatial allocation, shown in Figure 29, predicts over 67 MW of non-coincident growth and 4 MW of behind-the-meter solar PV. This has resulted in 2 N-0 overloads and 5 N-1 contingency distribution risks. There are no planned capacity projects in Front Range identified for the 5-year distribution plan. The Company is performing several end-of-life replacement projects for aging assets in the Front Range division. The major asset deployments and replacements are detailed in Figure 29.

Figure 29: Front Range Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	2	5	2	11

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	0	0	0	0

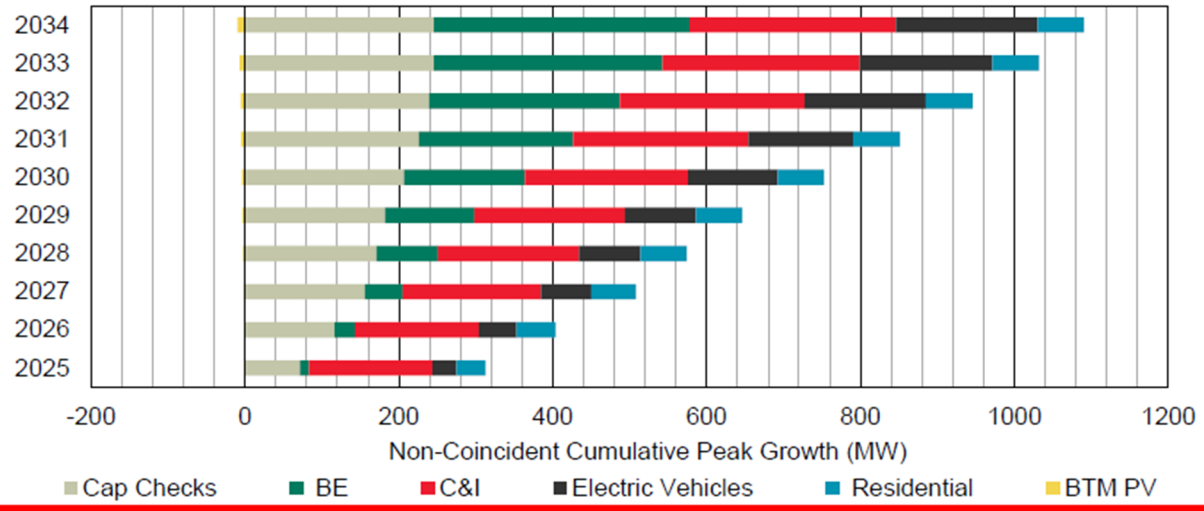
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
5	0	2	0	0

Gateway Planning Division

The distribution system supporting the Gateway division consists of 8 substations, 16 substation transformers and 56 distribution feeders. The division spans approximately 237 square miles covering northern Aurora primarily north of I-70 and east of E-470, shown in Figure 24. The nominal distribution system voltage is primarily 13.2 kV, with the exception of the 24.9 kV distribution system supporting Denver International Airport.

The Company has seen significant growth in Gateway, with approximately 314 MW of non-coincident capacity check demand approved. Gateway's forecasted spatial allocation, shown in Figure 30, predicts over 845 MW of non-coincident growth and 10 MW of behind-the-meter solar PV. This has resulted in 43 N-0 overloads and 12 N-1 contingency distribution risks. Distribution Planning has developed 15 capacity projects to mitigate these risks, which will add approximately 340 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the Gateway division. The major asset deployments and replacements are detailed in Figure 30.

Figure 30: Gateway Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	43	12	155	18

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	15	3	11	34

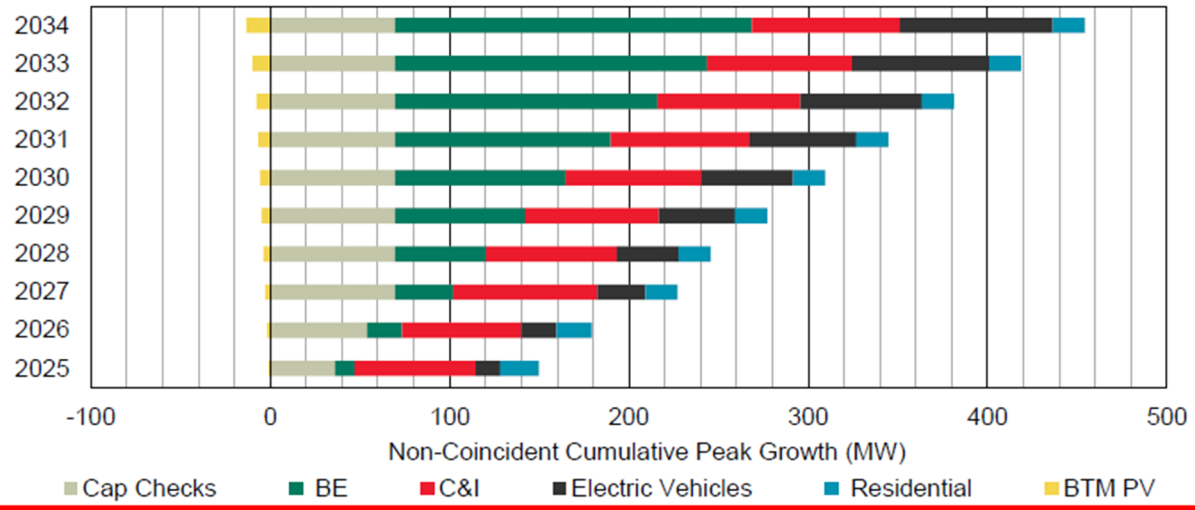
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
1	2	0	0	2

Greeley Planning Division

The distribution system supporting the Greeley division consists of 12 substations, 18 substation transformers and 44 distribution feeders. The division spans approximately 813 square miles, shown in Figure 24. The nominal distribution system voltage in Greeley is 12.47 kV.

The Company has seen moderate growth in Greeley, with approximately 125 MW of non-coincident capacity check demand approved. Greeley's forecasted spatial allocation, shown in Figure 31, predicts over 385 MW of non-coincident growth and 13 MW of behind-the-meter solar PV. This has resulted in 38 N-0 overloads and 12 N-1 contingency distribution risks. Distribution Planning has developed 15 capacity projects to mitigate these risks, which will add approximately 260 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the Greeley division. The major asset deployments and replacements are detailed in Figure 31.

Figure 31: Greeley Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	38	12	112	38

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	15	5	9	26

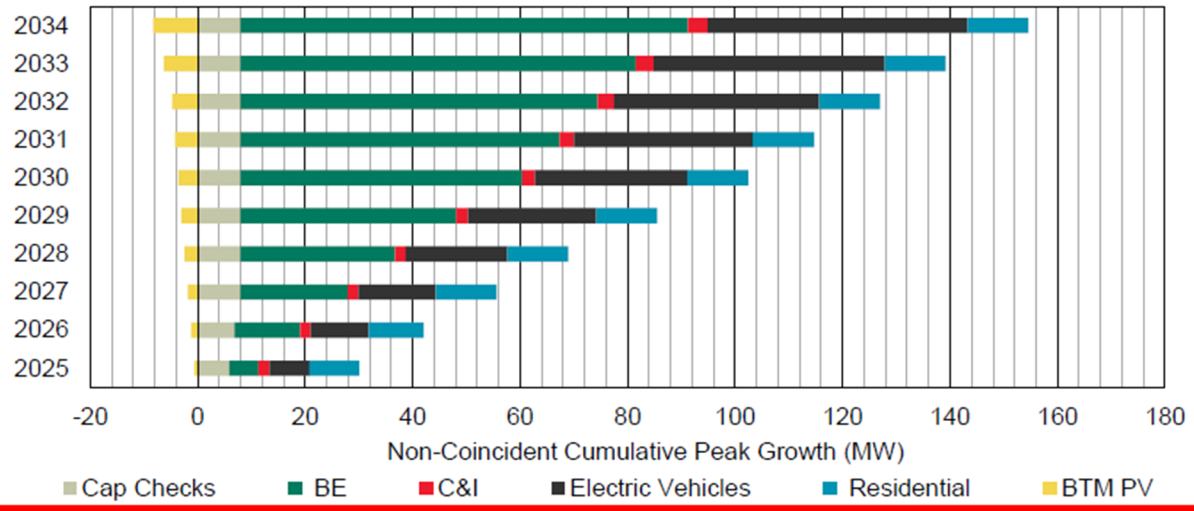
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
1	2	0	1	2

Mountain Planning Division

The distribution system supporting the Mountain division consists of 8 substations, 14 substation transformers and 24 distribution feeders. The division spans approximately 364 square miles and primarily covers Summit County, shown in Figure 24. The nominal system voltage is 24.9 kV.

The Company has seen low growth in the Mountain division, with approximately 14 MW of non-coincident capacity check demand approved. The Mountain division's forecasted spatial allocation, shown in Figure 32, predicts over 146 MW of non-coincident growth and 8 MW of behind-the-meter solar PV. This has resulted in 10 N-0 overloads and 3 N-1 contingency distribution risks. Distribution Planning has developed one capacity project to mitigate the risks, which will add approximately 28 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the Mountain division. The major asset deployments and replacements are detailed in Figure 32.

Figure 32: Mountain Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	10	3	15	5

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	1	0	1	1

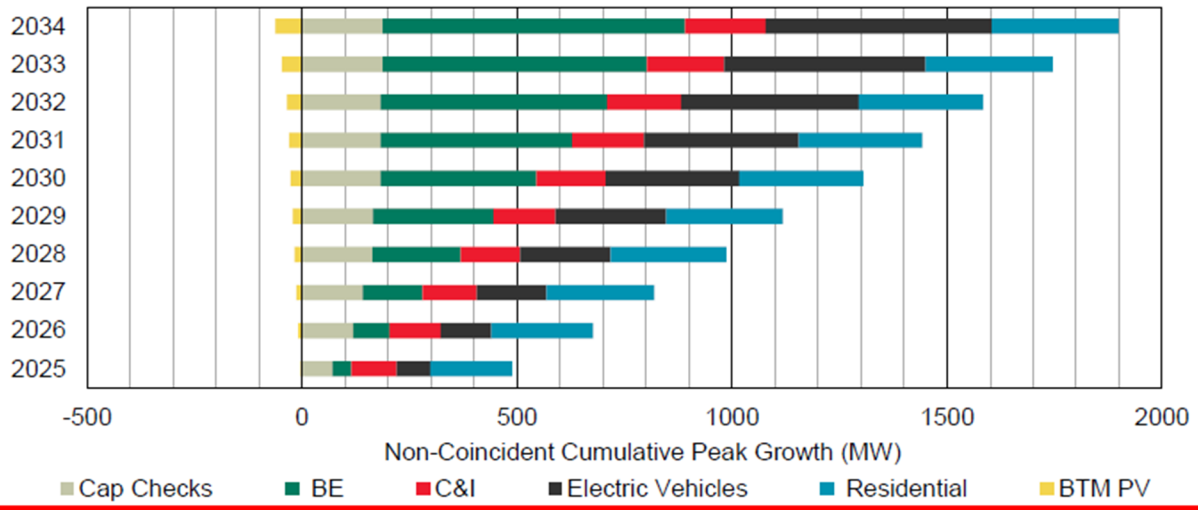
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
3	0	1	0	4

North Metro Planning Division

The distribution system supporting the North Metro division consists of 19 substations, 40 substation transformers and 148 distribution feeders. The division spans approximately 276 square miles, shown in Figure 24. The nominal system voltage is 13.2 kV.

The Company has seen high growth in the North Metro division, with approximately 295 MW of non-coincident capacity check demand approved. The North Metro division's forecasted spatial allocation, shown in Figure 33, predicts over 1.7 GW of non-coincident growth and 63 MW of behind-the-meter solar PV. This has resulted in 139 N-0 overloads and 67 N-1 contingency distribution risks. Distribution Planning has developed 31 capacity projects to mitigate these risks, which will add approximately 500 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the North Metro division. The major asset deployments and replacements are detailed in Figure 33.

Figure 33: North Metro Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	139	67	457	43

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	31	5	12	50

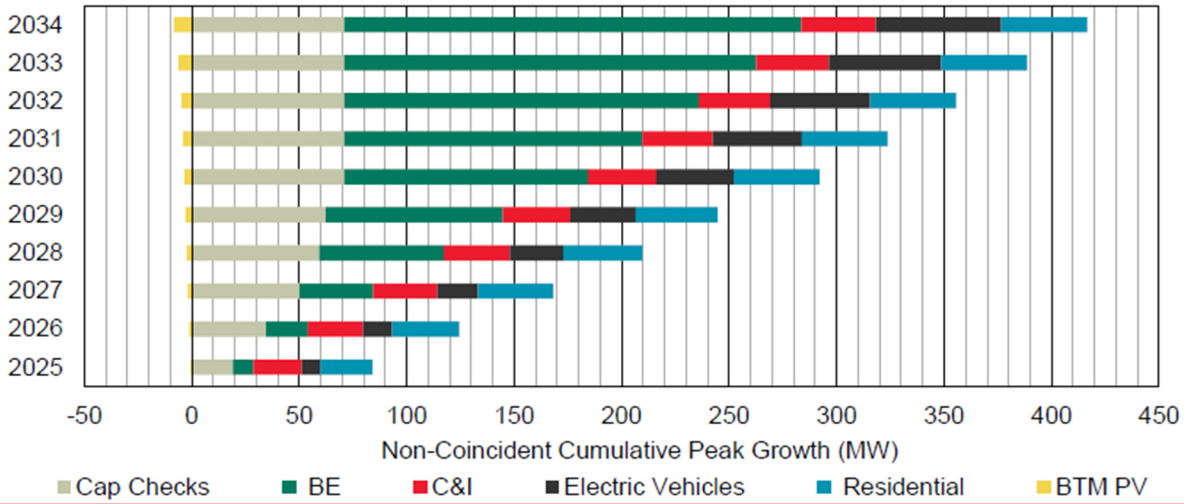
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
3	4	7	4	0

Northern Planning Division

The distribution system supporting Northern division consists of 9 substations, 12 substation transformers and 33 distribution feeders. The division spans approximately 193 square miles, shown in Figure 24. The nominal system voltage is 13.2 kV.

The Company has seen moderate growth in the Northern division, with approximately 96 MW of non-coincident capacity check demand approved. The Northern division's forecasted spatial allocation, shown in Figure 34, predicts over 346 MW of non-coincident growth and 8 MW of behind-the-meter solar PV. This has resulted in 25 N-0 overloads and 11 N-1 contingency distribution risks. Distribution Planning has developed 11 capacity projects to mitigate these risks, which will add approximately 170 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the Northern division. The major asset deployments and replacements are detailed in Figure 34.

Figure 34: Northern Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	25	11	72	20

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	11	2	9	17

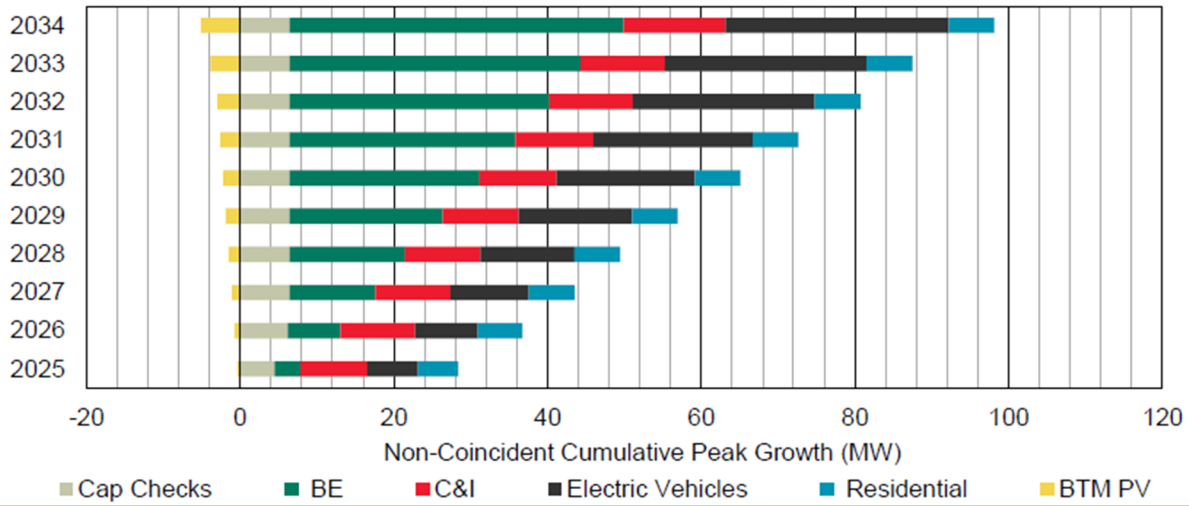
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
2	0	2	0	3

San Luis Valley Planning Division

The distribution system supporting the San Luis Valley division consists of 14 substations, 24 substation transformers and 34 distribution feeders. The division spans approximately 1,094 square miles, shown in Figure 24. The nominal system voltage is a combination of 24.9 kV and 13.2 kV.

The Company has seen low growth in the San Luis Valley division, with approximately 14 MW of non-coincident capacity check demand approved. The San Luis Valley division's forecasted spatial allocation, shown in Figure 35, predicts over 92 MW of non-coincident growth and 5 MW of behind-the-meter solar PV. This has resulted in 9 N-0 overloads and 7 N-1 contingency distribution risks. Distribution Planning has developed six capacity projects to mitigate these risks, which will add approximately 65 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the San Luis Valley division. The major asset deployments and replacements are detailed in Figure 35.

Figure 35: San Luis Valley Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	9	7	15	13

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	6	0	5	5

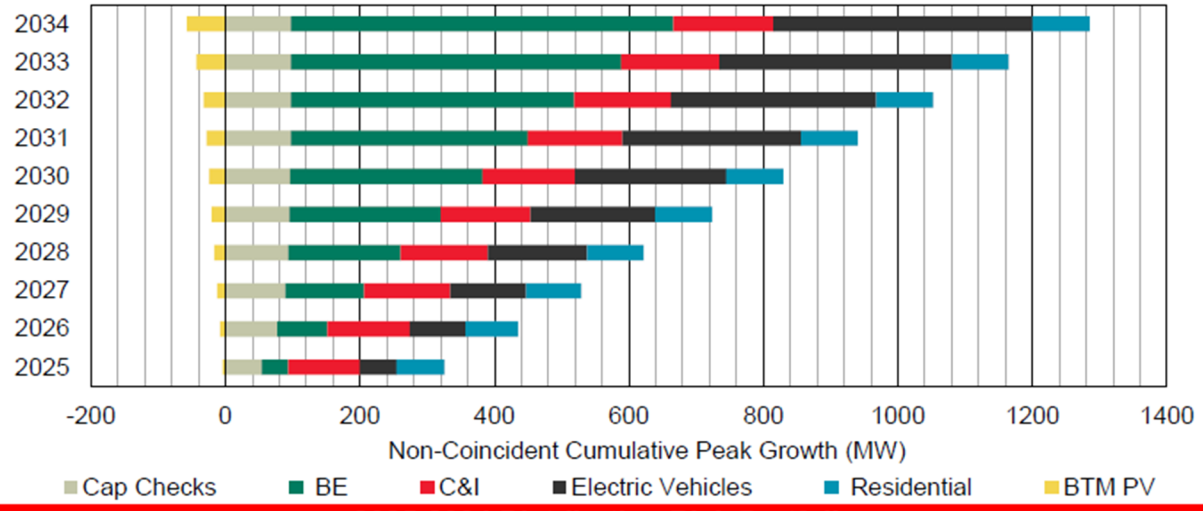
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
4	1	1	0	1

Southeast Metro Planning Division

The distribution system supporting the Southeast Metro division consists of 17 substations, 37 substation transformers and 144 distribution feeders. The division spans approximately 242 square miles, shown in Figure 24. The nominal system voltage is 13.2 kV.

The Company has seen high growth in the Southeast Metro division, with approximately 152 MW of non-coincident capacity check demand approved. Southeast Metro division's forecasted spatial allocation, shown in Figure 36, predicts approximately 1.2 GW of non-coincident growth and 58 MW of behind-the-meter solar PV. This has resulted in 117 N-0 overloads and 46 N-1 contingency distribution risks. Distribution Planning has developed 22 capacity projects to mitigate these risks, which will add approximately 350 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the Southeast Metro division. The major asset deployments and replacements are detailed in Figure 36.

Figure 36: Southeast Metro Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	117	46	281	36

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	22	5	15	35

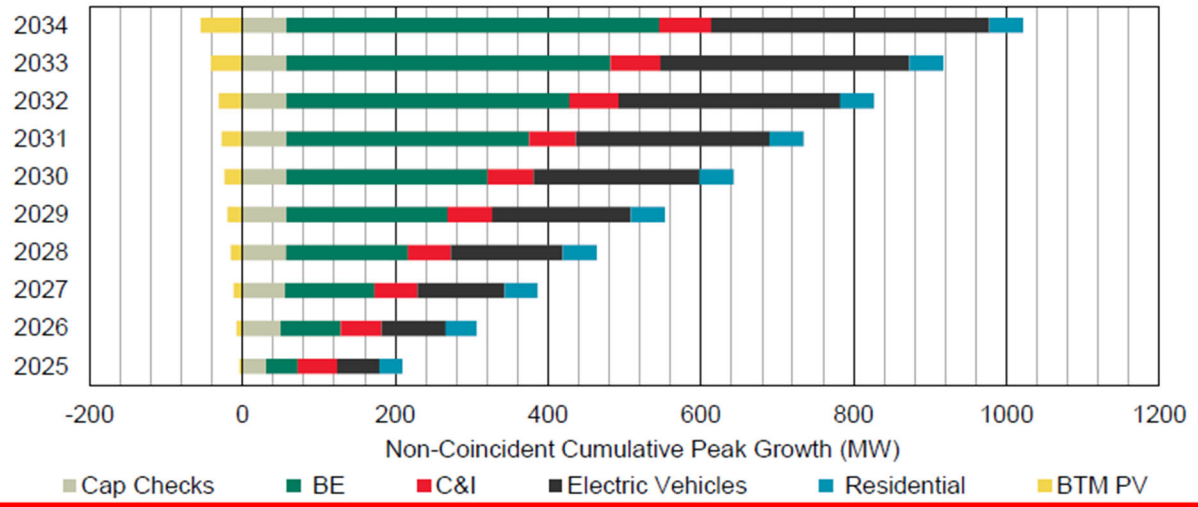
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
2	3	3	9	0

Southwest Metro Planning Division

The distribution system supporting the Southwest Metro division consists of 15 substations, 32 substation transformers and 114 distribution feeders. The division spans approximately 242 square miles, shown in Figure 24. The nominal system voltage is 13.2 kV.

The Company has seen moderate growth in the Southwest Metro division, with approximately 84 MW of non-coincident capacity check demand approved. Southwest Metro division's forecasted spatial allocation, shown in Figure 37 predicts approximately 965 MW of non-coincident growth and 55 MW of behind-the-meter solar PV. This has resulted in 83 N-0 overloads and 74 N-1 contingency distribution risks. Distribution Planning has developed 23 capacity projects to mitigate the risks, which will add approximately 440 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the Southwest Metro division. The major asset deployments and replacements are detailed in Figure 37

Figure 37: Southwest Metro Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	83	74	195	37

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	23	4	12	44

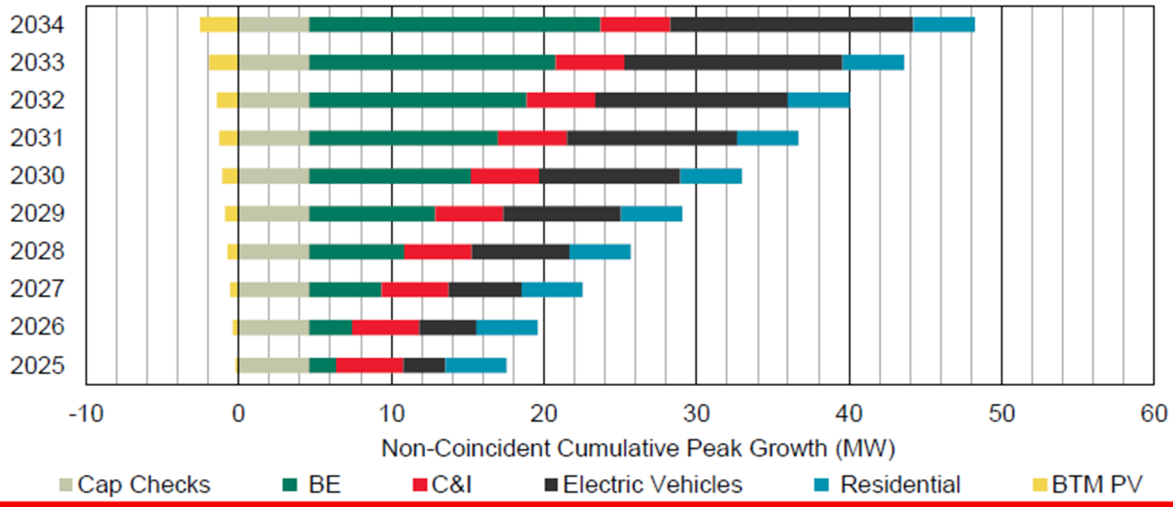
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
5	5	1	4	0

Sterling Planning Division

The distribution system supporting the Sterling division consists of 6 substations, 8 substation transformers and 15 distribution feeders. The division spans approximately 567 square miles, shown in Figure 24. The nominal system voltage is 13.2 kV.

The Company has seen low growth in the Sterling division, with approximately 8 MW of non-coincident capacity check demand approved. The Sterling division's forecasted spatial allocation, shown in Figure 38, predicts approximately 44 MW of non-coincident growth and 2.5 MW of behind-the-meter solar PV. This has resulted in 6 N-0 overloads and 2 N-1 contingency distribution risks. Distribution Planning has developed three capacity projects to mitigate the risks, which will add approximately 10 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the Sterling division. The major asset deployments and replacements are detailed in Figure 38.

Figure 38: Sterling Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	6	2	16	3

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	3	0	0	0

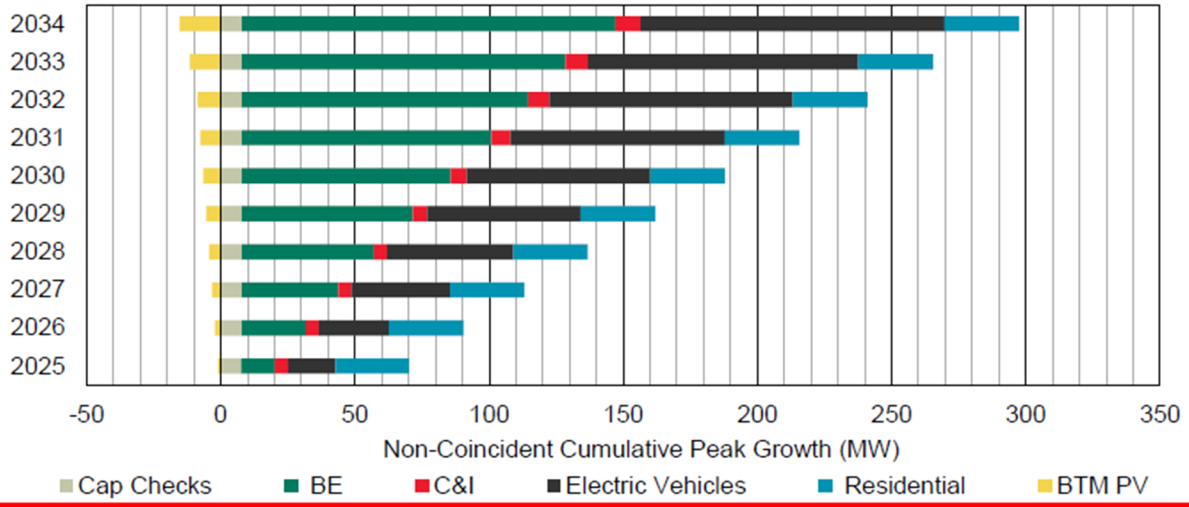
2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
1	0	4	1	1

Western Planning Division

The distribution system supporting the Western division consists of 15 substations, 22 substation transformers and 39 distribution feeders. The division spans approximately 444 square miles, shown in Figure 24. The nominal system voltage is a combination of 24.9 kV and 13.2 kV.

The Company has seen low growth in the Western division, with approximately 13 MW of non-coincident capacity check demand approved. The Western division's forecasted spatial allocation, shown in Figure 39, predicts approximately 290 MW of non-coincident growth and 15 MW of behind-the-meter solar PV. This has resulted in 28 N-0 overloads and 11 N-1 contingency distribution risks. Distribution Planning has developed seven capacity projects to mitigate these risks, which will add approximately 70 MW of capacity over the next five years. The Company is also performing several end-of-life replacement projects for aging assets in the Western division. The major asset deployments and replacements are detailed in Figure 39.

Figure 39: Western Division - Distribution Grid Needs



2025-2034 Distribution Risk Portfolio				
Risk Type	N-0 Overloads	N-1 Contingencies	Total Overloads (MW)	Largest Contingency (MW)
Assets at Risk	28	11	73	18

2025-2029 Distribution Capacity Projects				
Asset Type	Project Count	Substations	Transformers	Feeders
Count	7	1	5	6

2025-2029 Proactive End-of-Life Replacement Projects				
Transformers	Switchgears	Breakers	Relays	Remote Terminal Units
1	0	1	0	3

As required by Rule 3532, Public Service has further delineated grid needs into short-term grid needs and long-term grid needs as described below. Specific short-term and long-term distribution risks can be found in Attachment DCM-2.

SHORT-TERM GRID NEEDS

Short-term Grid Needs are those defined as occurring in years zero through three in the distribution system load forecast. The implementation time frames for each type of capacity project has increased due to supply chain challenges and permitting challenges. These risks are driven primarily by known load growth received by the Company as a new service application. These applications are processed through the Capacity Check process and tend to result in short-term capacity projects. While not all risks can be resolved in the short-term, projects are developed for each risk.

Table 6: Short-term Grid Needs

Grid Need Type	N-0	N-1
Short-term	517	278

LONG-TERM GRID NEEDS

Long-term grid needs are those which are defined as occurring in years four through ten in the distribution system load forecast. Long-term needs are typically addressed with large projects such as the installation of new substation transformers, construction of new feeders, replacement or upgrade of existing transformers, or new substations. As new growth is approved on the system, the system forecast is refreshed to account for the new load additions.

Table 7: Long-term Grid Needs

Grid Need Type	N-0	N-1
Long-term	106	0

RATABLE PROCUREMENTS

The Company evaluated areas on the distribution system where long-term grid needs could be candidates for ratable procurements[24]. Since all long-term risks were N-0 overloads, N-1 contingency risks were not considered viable for ratable procurements. Long-term N-0 overload risks without a funded capacity project in the 5-year capital budget were considered for ratable procurements. Several short-term risks that are in the same location as some of the long-term risks were also included in the ratable

[24] "Ratable procurement" means the procurement of incremental DER capacity to defer or avoid long-term traditional utility infrastructure or grid needs driven by steady load growth.

procurement candidate list. Overall, long-term risks on five distribution assets are being proposed for ratable procurements. The Company is evaluating a subset of these five locations as potential targeted demand response areas, discussed in more detail in Section XII.

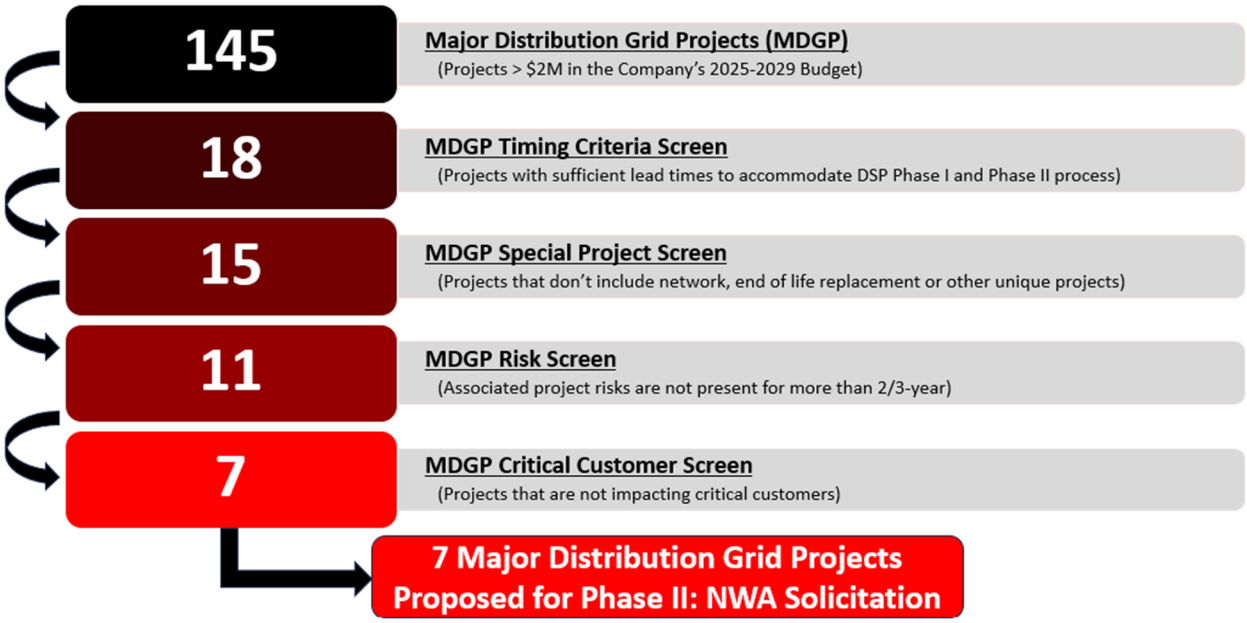
Table 8: Ratable Procurements from Grid Needs Assessment

Division	Asset Type	First Year of Risk
Front Range	Feeder	2033
Southwest Metro	Bank	2031
Western	Bank	2033
Western	Bank	2031
Western	Feeder	2030

NON-WIRES ALTERNATIVES SUITABILITY SCREENING

Based upon the application of the Suitability Criteria in Rule 3534(b), the Company identified 145 projects which meet or exceed the $2 million threshold for consideration as Major Distribution Grid Projects ("MDGP"s). The additional NWA suitability screens implemented by the Company in the inaugural 2022 Distribution System Plan filing were applied the MDGPs, outlined in Figure 40.

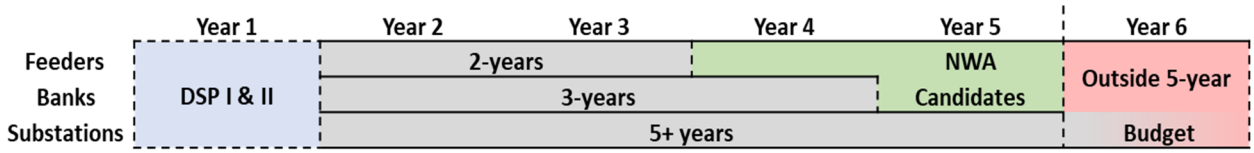
Figure 40: NWA Suitability Screening Process



A notable change in the suitability screening is the project timing screening. Supply chain and permitting challenges are leading to longer implementation timeframes for various project types. It typically takes the company about two years to complete a distribution

feeder project and a minimum of three years for a substation bank project. Therefore, only feeder projects in the last two years of the 5-year budget and substation bank projects in the final year of the budget were deemed eligible for NWA consideration, as detailed in Figure 41.

Figure 41: Timing Impacts of the 2024 DSP on the 2025-2029 Project



As noted in Figure 40, of the initial 145 Major Distribution Projects, seven projects were deemed suitable for NWA consideration. Those projects are listed in Figure 42.

Figure 42: NWA Candidate Projects

Project Name	Project Type	Planning Division	Required In-Service Year	N-0 Risk?	N-1 Risk?
Berthoud TR2	New Bank	Northern	2029	No	Yes
COBB1397 Feeder	Feeder	Northern	2028	Yes	No
Dakota TR3	New Bank	Denver Metro	2029	Yes	No
Daniels Park TR1	New Bank	Southeast Metro	2029	No	Yes
GREE1043 Feeder	Feeder	Southeast Metro	2028	Yes	No
RUSS2578 Feeder	Feeder	North Metro	2028	Yes	No
West TR3	New Bank	Southwest Metro	2029	Yes	Yes

For each project, the Company has provided the full magnitude, maximum consecutive hours and the annual hours that each risk is present over the full 10-year forecast period, referred to as the System Load Relief Requirements ("SLRR"). This information can be found in DCM-2. This attachment also provides the amount of controllable demand from customers participating in any of the Company's DR programs. The Company will evaluate and consider how much of this flexible demand to account for the total SLRR needed for each project during the Phase II technology neutral solicitation process. The Company plans to conduct a stakeholder workshop to discuss this, including the 25 percent safety margins applied to the magnitude and duration of the NWA SLRR prior to the release of the solicitation.

POSTING THE GRID NEEDS ASSESSMENT TO THE WEB PORTAL

After the 2022 Distribution System Plan filing, the Company began developing a secure web portal to allow users who have signed a non-disclosure agreement to see generation Hosting Capacity maps in a non-heat map format to provide more insights in the system's capacity. The portal went live on March 26, 2024, at which time the Company uploaded the tabular data for the generation HCA results along with the 2022 Distribution System Plan Grid Needs Assessment attachment. The Company will upload the 2024 Grid Needs Assessment attachment to the portal once the 2024 DSP Action Plan has been filed. Non-wires Alternatives Cost benefit Methodology

Consistent with the Settlement Agreement reached in the Company's last Distribution System Plan, the Company has updated its NWA cost benefit analysis ("CBA") handbook to incorporate the Social Cost of Methane and the Social Cost of Carbon. In addition, the Company has aligned the non-energy benefits with the most recently approved values in its DSM Strategic Issues cases (25% for income qualified customers and 10% for non-income qualified customers). Apart from these minor updates, the Company has not made any other changes to the cost benefit analysis handbook that was presented and approved as part of its last Distribution System Plan. An updated copy of the Company's NWA CBA is provided as Appendix 2 To the extent that the Company receives bids as part of the Phase II Solicitation, the NWA cost benefit tool that was developed by ICF has the capability to reflect the Company's most recently approved weighted average cost of capital ("WACC") as well as a model a sensitivity using a 2.5% discount rate.

VIII. NON-WIRES ALTERNATIVE SOLICITATION PROCESS

Commission Rule 3534(d) requires the Company to conduct a technology-neutral competitive solicitation for all major distribution grid projects that meet the NWA suitability screening criteria. This section details the Company's proposed NWA solicitation process for Major Distribution Grid Projects.

DEFINING NWA REQUIREMENTS

As part of the technology neutral request for proposal ("RFP") documentation the Company will provide an exhibit defining, in detail, the nature of each Grid Need. A model of how this information would be presented is proposed within Appendix 4 (described further below). These requirements are unique to every Grid Need and therefore there will be a distinct and discrete RFP for each project. This includes defining the total number of hours at risk, the duration of the risk both on a daily and annual basis, and any other important considerations for bidders to be able to develop bids that can safely address the system risk. As noted in the Company's Phase II DSP report, the Company made several revisions to the bid packages to reflect project specific needs based upon the feedback of the independent evaluator ("DNV") and ICF. These revisions, which the Company plans to carry forward into the bid packages for this DSP, include providing:

- More detail about the capital project developed by the Company;
- Defining N-0 and N-1 risks and how they relate to the solicitation;
- Asset Mapping to show how feeders and transformers are configured in both N-0 and N-1 scenarios. This allows developers to know where they can site projects to support specific risks in the solicitation;
- Expanding the Timing of Need section to include additional details such as Tabular and graphical data showing the peak day demand curve for each risk in the solicitation; and
- A breakdown of the customer class type and count per feeder.

Consistent with the Settlement Agreement in the last Distribution System Plan, the Company will provide the full magnitude and duration of the load relief requirements in the bidder packages for any approved NWA projects from the Phase II process.

Solicitation and Evaluation of NWA Bids

The process for soliciting, evaluating, and selecting NWAs that may be proven to be cost effective is summarized by Figure 43. This process is limited to 120 days as per

Commission Rule 3528(c)(I), and the Company proposed the below solicitation timelines in its inaugural Distribution System Plan.

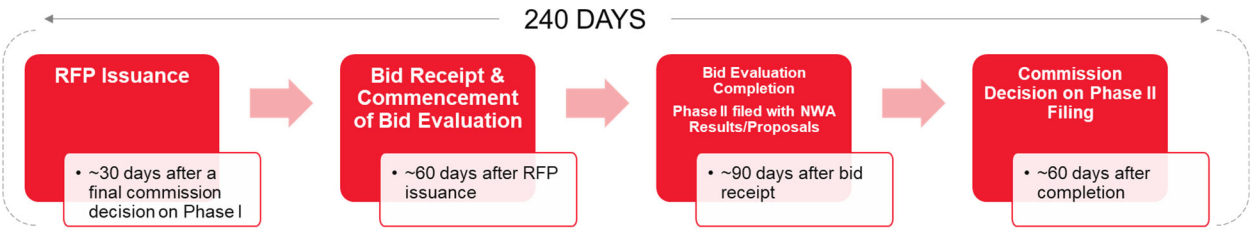
Figure 43: Timeline for DSP RFP Process Proposed in Inaugural DSP



As foreshadowed in the Company's Phase II DSP report in Proceeding No. 22A-0189E, the Company noted many of challenges with the timing of the 120 days that exist in Rule 3528 (c)(I). The timelines and process in the DSP Rules were intended to follow the Electric Resource Planning process. In hindsight, the ERP process is one which is relatively mature, having been refined through numerous iterations. Therefore, it is well understood by bidders and other stakeholders.

For the purposes of NWA solicitation, the requirement to file a Phase II DSP within 120 days of the Phase I is, in the Company's implementation experience, too short in duration. Notably, the ERP process has flexibility in the timing for the Company to issue an RFP (60 days in normal practice), plus 90 days per rule to receive bids. The current DSP rules do not have the same flexibility and/or timing, which significantly compresses the process timeline. Therefore, the Company is seeking a variance to extend the bidding process to better align with the timelines used in the ERP process. A proposed process is provided in Figure 44 below.

Figure 44: Proposed Revised Solicitation Timeline for this DSP



Proposed RFI for NWAs

Given that the Company has identified more than three times the number of NWA candidates since its inaugural Distribution System Plan, the Company is proposing several refinements to the solicitation process aimed at improving the chance of successful projects and maximizing efficiency. First, the Company is proposing to conduct a request for information ("RFI") prior to issuing any specific RFPs. The Company is

making this recommendation based on feedback provided by DNV GL in the NWA independent evaluator report filed in Proceeding No. 22A-0189E. Specifically, DNV GL noted:

> To ensure there are resources in the market that can meet the full (or modified) system need, Xcel Energy could conduct a request for information (RFI) process with potential bidders to identify potential solutions and costs before the full RFP process. An RFI can provide Xcel Energy with insights on whether bidders are interested in the potential project and what resources are available, and at what cost, to address the system need. The RFI process can reduce burden on potential bidders and Xcel Energy staff compared to the full RFP process as bidders can respond to them quicker than a full RFP and Xcel Energy staff will have information that can help them decide whether to move forward with an RFP or how to modify the RFP to align with what the market can provide.

The NWA RFP process is time intensive on both bidders and the Company and we agree with the recommendation that an RFI process can potentially reduce inefficiencies that are reflected in a full RFP. The Company intends to use this process to solicit feedback from stakeholders on a number of topics, including input on 25 percent safety margin that the Company applies in its evaluation of NWAs.

IX. INVESTMENT NEEDS AND BUDGET

The grid needs addressed in the prior section are a major driver of investment needs, helping to unlock customer opportunities and outcomes aligned with State policy. These grid needs are not, however, the only driver of investment required to implement this Plan. Indeed, the health of our distribution system assets is critical to our ability to ensure that our customers receive safe, reliable, and cost-effective electricity. We make investments each year to maintain our vast system of overhead feeders and poles, underground cables, and substation equipment that form the last critical miles of the electric system. These investments in asset health, reliability, and resiliency are just as important to providing customers with more choice and driving State policies as investments creating new capacity on the system are, and this importance is reflected in the budget underlying this Plan. As we deploy new infrastructure to unlock additional capacity, it is important that we maximize the use and useful lives of the equipment through asset health and reliability investments. And further, many investments drive multiple purposes, supporting policy and reliability at the same time.

Against that backdrop, our local grid requires a strong core foundation, and many of our assets are at or are past their anticipated useful life. As a result, we are planning greater investments to replace assets that are more likely to cause an outage. It is our goal to able to replace assets closer to their estimated end of useful life while balancing customer costs. These investments allow us to maintain reliable service for our customers and to harden our system as appropriate to make it more resilient to extreme weather events. Areas and issues of significance to reliability and resiliency have been highlighted in Public Service's annual Electric Quality of Service Plan ("QSP") filings as well as Investigatory Proceeding 24I-0394E regarding outages on the Company's electric system.

Many of these projects are classified as Asset Health and Reliability (a category addressed in more detail below) and are related to infrastructure that is reaching the end of its useful life and may experience higher failure rates – and that, as a result, negatively impacts reliability of service while increasing O&M expenses. Distribution performance is monitored to ensure that they provide reliable service throughout the year. When poor-performing assets are identified, projects that will improve asset performance are included in the budget. Asset Health and Reliability budget categories include new and ongoing projects that are performed annually to address the age and condition of our distribution facilities.

INVESTING IN ASSET HEALTH AND RELIABILITY FOR THE LOCAL GRID

Public Service's investments in Asset Health and Reliability fall into two primary categories – routine projects and larger discrete specific projects. Routine projects are those that are performed each year to replace aging and worn distribution facilities based on the age profile and overall reliability performance of these facilities. This includes replacement of underground cable, poles, and substation equipment that have reached the end of their useful life. This category also captures replacements due to storms and public damage. In addition to these routine projects that are performed each year, Distribution also undertakes non-routine discrete projects that relate to asset renewal (addressing aging infrastructure with specific conversion or upgrade projects) or reliability (where the age of facilities impacts failures, reliability, and customer outages).

To maintain the integrity, reliability, and safety of its operations, the Company is increasing its investments that maintain Asset Health. This includes additional investment in cable replacement, pole replacements, targeted reliability projects, and targeted undergrounding of poor performing overhead systems to name a few. This equipment remains the backbone of the distribution system, and these assets need to be fully operational to provide electric service and to support the clean energy transition as more DER are connected to the grid. As the operation of the distribution system becomes more complex through more integrated devices and with the increased adoption of DER, it will be increasingly important for the Company to invest in Asset Health and Reliability projects to ensure safe, reliable, resilient service for our customers.

Expansion of both DERs and electrification generally will require that distribution equipment be designed to a modern standard when these new generation sources or load come online. Accommodating these resources requires that Public Service's distribution equipment be robust enough to maintain proper voltage levels, carry the required power, and have operability with modern grid assets. In addition, these DERs are accelerating the wear on some aging facilities and will also prompt the need for changes to relay protection schemes and other equipment.

Public Service has many programs aimed to maintain and improve reliability. Each program targets areas or assets that require renewal based on age or condition that can impact experience of customers. Major reliability programs consist of Vegetation Management, major asset investments, Feeder Performance Improvement Program, Wildfire Mitigation Plan, the Electric Quality of Service Plan ("QSP"), and Advanced Grid Intelligence and Security ("AGIS").

Due to escalation of wildfire threats across Colorado in the past few years, the WMP has been updated reflecting Public Service's continued focus on protecting customers while maintaining safety and reliability. The updated WMP incorporates new risk assessment

methodologies, new technology, expanding mitigation programs, and incorporating new mitigation programs consistent with utility practice. The Company is also targeting reliability issues that affect Disproportionately Impacted Communities.

Public Service filed an updated QSP tariff with a reliability performance incentive structure that places additional focus on disproportionately impacted communities ("DI Communities") as identified in the state's Enviroscreen tool. Public Service is committed to considering impacts on disproportionately impacted communities in our distribution planning process and electric reliability across all customers.

Asset Health and Reliability projects improve the overall customer service levels by supporting higher levels of DER adoption, reducing outage events, and improving overall reliability and resiliency performance. Thus, it is important that the Company continue to make necessary investments in the backbone of our system as well as new technologies to ensure that reliability is maintained on the system, while also advancing customer opportunities (e.g., electrification and DER adoption) and achievement of State policy objectives.

Another area we expect to make greater investments in the near-term is in our Substation Renewal program, to move toward replacing these assets closer to the end of their useful life. This program is focused on maintaining the reliability and resiliency of the Company's substations in Colorado through the replacement of key substation components. One of the main substation components is transformers. Substation transformers are fundamental to the reliability of our distribution system. They are one of the most expensive components we operate and have long manufacturer lead times (currently 3 years or more in some cases). While transformer failure is not a common occurrence, when a substation transformer fails, the consequences are high as it often results in thousands of customers losing electric service. There are a number of transformers on our system that are beyond their expected useful life, based on age and our annual analysis and trending of dissolved gasses in the transformer oil, and we risk a greater number of transformer failures that can result in unplanned outages for customers, if these assets are not replaced in a timely manner. Transformer renewal projects are planned and prioritized including factors such as: concurrent projects, load growth, future system changes, and construction efficiency.

For example, when replacing a transformer, current and long-term load growth is considered in selecting the transformer power capacity which has led us to install larger standard sized transformers or even consolidate/remove transformers to save money for our customers in the long run. Another example is replacing transformers and connected switchgear at the same time to minimize outages and provide construction efficiency over having separate projects. In addition to transformers, there are several other important

components to a substation such as switches, breakers, relays, and fences that also must be maintained and in working order to ensure reliability.

This program also includes investments in our spare and mobile transformer fleet. Our spares and mobile transformers are essential assets that – among other things – enable the Company to perform upgrades and maintenance on existing substations and respond to transformer failures. Additionally, this allows quicker restoration of power to customers when a substation transformer fails, and a new permanent transformer must be installed. As mentioned previously, with 3+ year lead times, having a robust and strategic spare and mobile transformer fleet is key to maintaining reliable service for our customers across our Colorado service territory.

BUDGETING FOR INVESTMENTS INTO THE LOCAL GRID

Electric and gas utilities are long-term, capital-intensive businesses. Every year, we prepare a five-year financial forecast that is used to anticipate the financial needs of each Xcel Energy operating utility company, including Public Service. Historically, the majority of the distribution budgets have been dedicated to immediate customer reliability needs and other shorter-term investments impacted by the dynamic nature of the distribution system. This includes building and maintaining feeders, substations, transformers, service lines, and other equipment – as well as restoring customers and our system in the wake of severe weather and responding to local and other government requirements to relocate our facilities.

Preparing the distribution system for the future requires a fundamental and proactive shift in the planning and budgeting framework which has been able to meet the needs of our customers over the last century. Now, our budget framework incorporates not only the necessary work to maintain existing infrastructure and implement new infrastructure to meet known requirements, but also the forward-looking investments needed in new and expanded infrastructure, non-traditional solutions, technology, and workforce to prepare for the future and achieve the strategic outcomes of enabling the clean energy transition, maintaining and enhancing reliability and resilience, and modernizing our customers' interactions with the distribution grid. The health of our distribution system is critical to ensuring that we are able to continue to provide reliable electric service today and in the future.

Each year when a five-year budget is created and approved, the first-year budget is essentially "locked in." However, budgets for the subsequent two to five years are reevaluated in the next budgeting cycle and will necessarily change in response to new developments and changing policy priorities, and as business requirements change. As we get closer to when spending will occur, our forecasts become more refined, based on more relevant information for the upcoming period. Distribution budgets must maintain flexibility to adjust to emergent circumstances and weather.

DISTRIBUTION BUDGET CATEGORIES

Asset Health and Reliability: Projects classified as Asset Health and Reliability are related to infrastructure that is reaching the end of its useful life and is experiencing higher failure rates – and that, as a result, negatively impact reliability of service while increasing O&M expenses. Distribution assets are monitored to ensure that they provide reliable service throughout the year. When poor-performing assets are identified, projects that will improve asset performance are included in the budget. Examples of these types of projects include replacing underground tap and feeder cables, wood poles, overhead lines, substation equipment, transformers, and switchgear that have reached the end of

their lives. This category also captures asset replacements due to storms and public damage. The major budget category of Asset Health and Reliability includes projects and programs in the following subcategories:

- ***Cable replacement and assessment*:** Cable is the term the Company uses for underground distribution lines. Accordingly, the projects in this category involve the Company identifying underground line segments that should be replaced (the "assessment"), and the replacement of those lines. The Company determines whether cable needs to be replaced based on the performance of the cable and prioritizes the replacement of non-jacketed cable. This older type of cable has been performing worse than was expected when it was installed. The Company also considers which cable replacements will have the biggest impacts for customers. As a result, in addition to prioritizing replacements based on performance and expected performance, Public Service also considers which cable impacts more customers. Cable failures are the single leading cause of non-storm outages in the Company's service territory, and so these investments are an important tool for improving the reliability of Public Service's distribution system. While underground failures are the single largest cause of non-storm outages making up approximately 25% of the customer impact the majority of the remaining 75% of outages occur on the overhead system. As more of the system is undergrounded, that improves resilience.

- ***Routines*:** There are many different parts of the overall distribution system that have to be replaced in a given year. Public Service has specific sub-categories for cables and poles, but there are also many other individual system components, and these other miscellaneous replacements are in this category. In connection with our normal operation of the system, the Company will determine that specific parts of the system should be replaced because they have become inoperable or have degraded performance. The Company can identify the need for replacing this miscellaneous distribution equipment in a variety of manners. A Company crew might notice an issue while working in the field and use our system to generate a work order for the replacement. Or a component might fail. The failure could result in an outage, in which case it would be replaced as a part of the response to that outage. Even if there is not an outage, the Company could determine that the replacement is needed based on information regarding system performance, including information obtained and analyzed through AGIS or other sources. The Company may also identify the need to replace such equipment while investigating the cause of a reported problem. The Company's investment in routines supports reliability and reliance in multiple ways. By removing and replacing failed or failing equipment with newer parts, the Company is reducing the

risks of future outages and other problems. These replacements are also rebuilt to the latest standard which often results in significant improvements in performance or strength due to new materials. To take a couple examples, a porcelain component might be replaced with one made of polymer or wood cross-arms might be replaced by stronger fiberglass crossarms.

- ***Pole replacements***: Public Service physically inspects poles on a multi-year cycle. Every time a pole is inspected, it is either determined to be sufficient to remain in service or is identified as needing replacement. In recent years, the Company changed its standards for poles. As a result, when replacement poles are installed they are now stronger than used to be the case resulting in improved resilience. As older poles degrade and lose strength they are replaced, the overhead lines they support become less likely to have weather-related outages. The strength of the Company's newer poles contributes to the improved reliability and resiliency.

- ***Line asset renewal programs*:** These projects involve replacement and rebuilding of overhead distribution lines that have reached the end of their life. These are discrete projects that are specifically identified in the DSP budget, and they often include the installation of reclosers. Line asset renewal programs improve the reliability and resilience of our system in multiple respects. First, rebuilding these segments of our overhead distribution system to our latest design standards results in overhead lines that are less likely to fail than if older equipment was kept in place. By increasing these investments, the Company is refreshing the age of key portions of the distribution system. The installation of reclosers also reduce the number of customers impacted by faults.

- ***Substation asset renewal programs*:** This category consists of the replacement of equipment within substations that is at the end of its life. Using various information regarding the age and performance of equipment, the Company determines which items should be replaced in order to avoid failures. These programs only replace specific items of equipment within substations rather than entire substations. These programs are a mix of routines, with the amounts budgeted for types of projects that are expected based on historic information, and some specifically planned and budgeted projects. These projects support both reliability and resilience. By replacing failing and/or aging equipment, the Company reduces the risk of failures within our substations. This is important as failures of these assets would result in outages for a significant number of customers

- ***Substation asset renewal discrete projects*:** These are discrete projects that involve decommissioning and replacing specific substations that are older and that

should be replaced in order to keep the distribution system operating reliably. These projects are specifically planned and budgeted years in advance and are larger than routines. Replacing older substations helps with reliability and resilience by avoiding customer outages that would result if these assets were kept in service past the end of its useful life. The replacement assets are also built to the Company's current, more robust standards.

- ***Line asset renewal discrete projects*:** These are discrete projects that involve replacing distribution lines that are older and that should be replaced in order to keep the distribution system operating reliably. These projects are specifically planned and budgeted years in advance and are larger than routines. Replacing older distribution lines helps with reliability and resilience by avoiding customer outages that would result if these assets were kept in service past the end of its useful life. The replacement assets are also built to the Company's current, more robust standards

- ***Targeted undergrounding*:** Targeted undergrounding is a new program, in which the Company will identify specific overhead lines and replace them with underground lines based on the performance of existing overhead lines. Underground lines are more protected from weather impacts such as wind storms, snow, and ice, and so they suffer from fewer weather-related outages. By choosing to underground lines that have a history of weather-related issues, the Company can increase the reliability of the distribution systems in those portions of the system and can improve resilience. This work differs from mandated undergrounding in that the Company is making the decision of which lines to move underground rather than local governments. The Company is planning to begin targeted undergrounding in 2026 and will then increase the scope of the undergrounding in the following years

- **Emergent work:** In any given year, the Company will need to do some amount of capital work in response to damage caused by extreme weather. The Company obviously cannot know in advance how much storm-related work will be required in a given year. Accordingly, we budget storm reserves based on historic data. In addition, Public Services knows that every year there will be other relatively large asset health and reliability projects that will be needed which have not been budgeted or planned. This Plan refers to these categories of projects as "emergent work," and they are usually larger in scope than routines. While the reliability and resilience impacts associated with emergent work vary depending on the nature of the project, this work supports both objectives by replacing failed or damaged materials and equipment with the latest design standard resulting in improved performance.

- **Failure reserves (substations):** This program includes investments in our spare and mobile transformer fleet. Our spare and mobile transformers are essential assets that – among other things – enable the Company to perform upgrades and maintenance on existing substations and respond to transformer failures.

Table 9: DSP Asset Health and Reliability Budget ($Millions)

ASSET HEALTH AND RELIABILITY	2025	2026	2027	2028	2029	Total
Asset Renewal Discretes - Lines	$0	$0	$1	$2	$0	$4
Asset Renewal Discretes - Substation	$4	$9	$8	$8	$3	$32
Cable Replacement and Assessment	$66	$67	$69	$71	$73	$346
Failure Reserves	$22	$23	$16	$19	$12	$92
Line Asset Renewal Programs	$18	$16	$16	$16	$16	$82
Pole Replacements	$51	$52	$54	$34	$35	$224
Routines	$83	$86	$89	$93	$95	$447
Substation Asset Renewal Programs	$29	$46	$58	$61	$63	$258
Targeted Undergrounding	$0	$8	$16	$42	$84	$150
Emergent - Asset Health	$14	$14	$14	$18	$18	$78
TOTAL	**$286**	**$320**	**$342**	**$364**	**$400**	**$1,713**

Capacity: This category includes capital investments associated with upgrading or increasing distribution system capacity to handle load growth on the system and to serve load when other elements of the distribution system are out of service. This category also allows the system to support the interconnection of additional DER, including rooftop solar, and greater EV adoption, both of which are key to achieving the Company's and Colorado's emission-reductions goals. This additional capacity is provided by constructing new substations and installing new or upgraded substation transformers and distribution feeders. Capacity projects generally span multiple years and are necessitated by increased load from either existing or new customers.

Table 10: DSP Capacity Budget ($Millions)

CAPACITY	2025	2026	2027	2028	2029	Total
Capacity Discretes - Line	$134	$195	$167	$159	$130	$784
Capacity Discretes - Substation	$124	$181	$252	$252	$236	$1,045
Grid Reinforcements	$11	$16	$33	$34	$34	$128
Routines and Programs	$15	$16	$17	$17	$18	$82
Emergent - Capacity	$5	$5	$10	$10	$9	$39
TOTAL	**$289**	**$413**	**$478**	**$472**	**$427**	**$2,078**

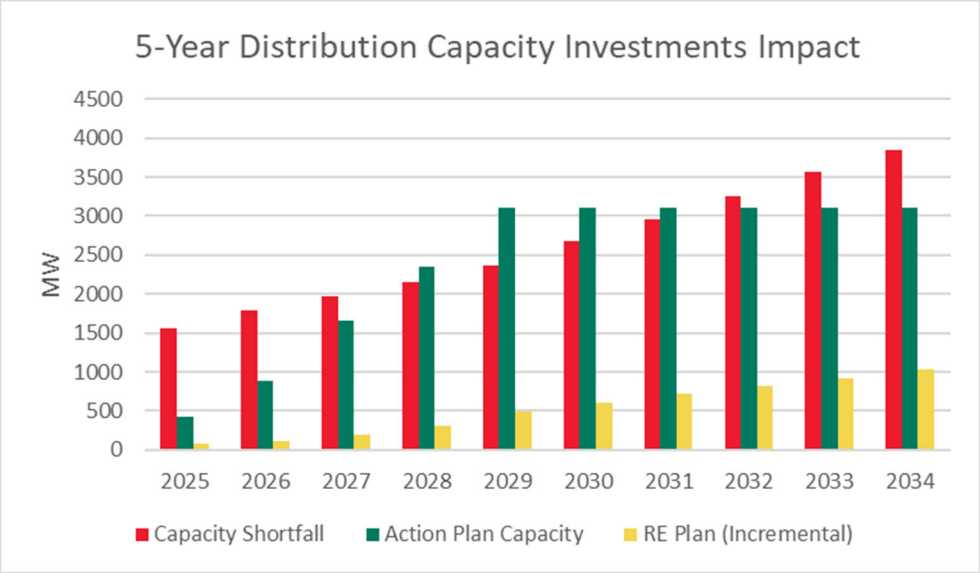
As stated previously within this Plan, this budget supports the deployment of the following assets on the distribution system.

Table 11: Infrastructure Enabled by Plan

Feeders	Substation Banks	New Substations
306	108	35

The benefit that comes from the deployment of these assets is shown in Figure 45 below. The capacity created through this 5-year action plan meets the growth forecasted through most of the 10-year Base Forecast. The Company will continue to reevaluate its forecasts and system needs annually to ensure proper growth.

Figure 45: 5-Year Action Plan Capacity Additions



The distribution capacity created through this 5-year Action Plan creates sufficient capacity for the incremental capacity growth for solar generation through the RE Plan. Available hosting capacity is locationally specific, so it is important for generation to be sited in areas where hosting capacity exists or is planned to be developed.

Transportation Electrification Plans: This category includes investment in infrastructure and customer facing EV programs for residential, commercial, and fleet customers included in the Company's Transportation Electrification Plans ("TEPs"). Certain costs associated with the Company's TEPs are budgeted within the Distribution business unit. The Company's EV-related programs are addressed through TEP proceedings, and associated costs are recovered through the Company's Commission-approved Transportation Electrification Program Adjustment.

Tools and Communication Equipment: This category includes tools, ROW, communications equipment, and locate costs associated with modifications or additions to the distribution system or supporting assets. Tools are needed to support a broad array of distribution projects and programs and serve multiple purposes. Certain Communication projects support Asset Health and Reliability projects, such as the communications equipment necessary to support the rebuilding of a substation or distribution line. Other Communication projects support capacity projects, including new feeders, substations or other equipment that is needed to increase system capacity. The equipment allows the Company to monitor and control the system, which enhances system reliability and resilience and allows for data gathering that supports our planning processes.

Table 12: DSP Tools and Communications Equipment Budget ($Millions)

TOOLS & COMMUNICATIONS	2025	2026	2027	2028	2029	Total
Communication - Asset Health and Reliability	$4	$3	$3	$0	$1	$11
Communication - Capacity	$4	$4	$7	$11	$10	$35
Tools, Locates, Misc.	$6	$6	$6	$6	$6	$29
TOTAL	**$13**	**$13**	**$16**	**$17**	**$17**	**$75**

Mandates: This category includes projects to relocate utility infrastructure in public rights-of-way ("ROW") when mandated to do so to accommodate public works projects such as a road widening or realignment project. These projects are normally identified during planning meetings with local communities. Examples of these projects include utility relocations for state and local governments such as the Central 70 project, which involves utility relocation in the I-70 corridor. Mandate projects fall into two general categories: (1) Discretes, Routines, and Programs; and (2) Community-Directed Undergrounding Projects:

- ***Mandate Discretes*, Routines, and Programs**: The projects in this category are relocations of existing distribution infrastructure located in public rights-of-way when the Company is required to do so in response to public works projects. For example, if a local government decides to widen or realign a road, the Company will need to relocate the lines located in the relevant right-of-way. It is the governmental entities that make the decisions that drive the need for these projects and so the timeframes are based on when those governments decide to proceed with their public works projects, when those decisions are communicated to the Company, and when the work is scheduled to be carried out. The name of this sub-category reflects the fact that while there are some larger projects can be planned years in advance, the discretes, much of it is also routines and programs.

- ***Community-Directed Undergrounding Projects*:** This work involves undergrounding existing overhead lines that is done at the request of local governments. Traditionally, the work was done pursuant to applicable franchise agreements. Now, however, the legislature has provided for similar undergrounding in portions of the Company's service territory that are not subject to franchise agreements. These projects improve reliability and resilience because underground lines tend to be more reliable than overhead distribution lines, and undergrounding makes our infrastructure more resilient against potential weather impacts.

Table 13: DSP Mandates Budget ($Millions)

MANDATES	2025	2026	2027	2028	2029	Total
Discretes, Routines, and Programs	$29	$30	$30	$31	$32	$151
Community-Directed Undergrounding	$24	$24	$25	$25	$26	$124
TOTAL	**$53**	**$54**	**$55**	**$56**	**$57**	**$275**

New Business: This work includes new overhead and underground extensions and services associated with extending service to new customers. Capital projects required to provide service to new customers include the installation or expansion of feeders, primary and secondary extensions, service laterals that bring electrical service from an existing distribution line to a new home or business, installation of street lighting, and converting existing streetlights to light-emitting diode ("LED") lights.

New Business projects are generally conducted through routines and are often not specifically identified in advance and can support a wide variety of end-uses and objectives, which makes it difficult to prospectively predict the extent to which New Business projects will advance energy policy goals. Given the very recent passage of SB 24-218, Company also does not yet have standardized processes and systems in place to track which of the New Business projects it ultimately executes advance specific State policies or goals, such as beneficial or transportation electrification, increasing access to affordable housing, or supporting the adoption of DERs in DI Communities. The Company expects to develop and refine these tracking capabilities in the coming years. To the extent the Company identifies specific New Business projects that strategically benefit or advance State energy objectives over the course of this DSP, the Company will bring the details of these projects forward to support appropriate cost recovery treatment through the Company's proposed April 1 GMAC reporting and review process.

New Business projects and programs fall into the following general categories:

- ***Underground extension and service routines and discretes*:** These programs and projects include underground distribution infrastructure necessary to extend new or expanded service to our customers. These projects can include the installation or extension of feeders, primary and secondary extensions, service laterals that bring electrical service from an existing distribution line to a new home or business, and street lighting projects. The "routines/discretes" wording indicates that some specific known projects are included in the Company's budgets and plans, but that there is also funding in the budget for routines. The Company cannot know in advance all of the new business projects that will arise in the coming years.

- ***Overhead extension and service routines and discretes*:** These programs and projects include overhead distribution infrastructure necessary to extend new or expanded service to our customers. These projects can include the installation or extension of feeders, primary and secondary extensions, service laterals that bring electrical service from an existing distribution line to a new home or business, and street lighting projects. The "routines/discretes" wording indicates that some specific known projects are included in the Company's budgets and plans, but that there is also funding in the budget for routines. The Company cannot know in advance all of the new business projects that will arise in the coming years.

- ***Meter and transformer purchases*:** These projects involve the installation of meters and transformer to serve new customers and replace existing meters and transformers.

- ***Street lighting*:** These projects involve the installation of street lighting and the conversion of existing street lights to light-emitting diode lights.

- ***Emergent work*:** The amount the Company set aside to support emergent service extension-related work.

Table 14: DSP New Business Budget ($Millions)

NEW BUSINESS	2025	2026	2027	2028	2029	Total
CIAC	($7)	($7)	($7)	($7)	($7)	($33)
Overhead Extension and Service Routines/Discretes	$5	$6	$5	$6	$6	$28
Underground Extension and Service Routines/Discretes	$60	$60	$62	$64	$66	$312
Meters and Transformers	$59	$61	$64	$70	$71	$325
Street Lights	$5	$5	$5	$5	$6	$26
Emergent - New Business	$10	$11	$15	$20	$21	$77
TOTAL	**$132**	**$137**	**$145**	**$159**	**$162**	**$735**

Wildfire Mitigation: This category consists of activities included in the Company's WMP. The WMP involves the following categories: System Resiliency, Operational Mitigations, Situational Awareness, and Customer Support. The programs included in the Company's proposed WMP are addressed in Proceeding No. 24A-0296E.

AGIS: This category consists of projects included in the Company's Advanced Grid Intelligence and Security initiative. The AGIS initiative involves the following foundational projects: Advanced Distribution Management System ("ADMS"), including Advanced Metering Infrastructure ("AMI"); the Field Area Network ("FAN"); Intelligent Field Devices that include Integrated Volt-VAR Optimization ("IVVO") and Fault Location Isolation and Service Restoration ("FLISR") (including Fault Location Prediction ("FLP"); and the Advanced Planning Tool ("APT" or "LoadSEER"). A portion of AGIS is the subject of a CPCN granted in Proceeding No. 16A-0588E for the AMI, FAN, and IVVO projects, which was then amended with respect to the distributed intelligence capabilities of the AMI meters in Proceeding No. 21A-0279E.

Looking more broadly across the categories, below is the capital budget across all distribution capital categories, including the capital budget for the last three years, i.e., 2022-2024, consistent with Rule 3532(d)(II)).

Table 15: 2022 – 2029 Distribution Capital Budget ($Millions)

Category	2022	2023	2024 (YTD)	2025	2026	2027	2028	2029	Total (2025-29)
Asset Health & Reliability	$173	$170	$145	$286	$320	$342	$364	$400	$1,713
Capacity	$35	$60	$71	$289	$413	$478	$472	$427	$2,078
Tools & Communications	$11	$13	$9	$13	$13	$16	$17	$17	$75
Mandates	$51	$48	$39	$53	$54	$55	$56	$57	$275
New Business	$85	$118	$132	$132	$137	$145	$159	$162	$736
Transportation Electrification Plan	$2	$0	$38	$53	$86	$90	$106	$107	$442
Wildfire	$98	$79	$66	$324	$412	$505	$455	$468	$2,164
AGIS	$92	$78	$61	$27	$2	$10	$0	$0	$39
Total:	**$547**	**$567**	**$561**	**$1,177**	**$1,436**	**$1,641**	**$1,628**	**$1,639**	**$7,522**

EQUIPMENT TO ADVANCE DISTRIBUTION ACTIVITIES

Under SB 24-218 authorizes current cost recovery for the revenue requirement associated with up to an additional one hundred fifty million dollars [$150 million] in investment to order equipment to advance distribution activities, such as power transformers, service transformers, capacitor banks, switch cabinets, and feeder cables, as long as the investments are prudently incurred for the purposes of achieving

economies of scale, addressing supply chain concerns, or other similar purposes.[25] In addition to the $52 million in equipment to advance distribution activities ("EADA") that the Company plans to order in 2025, the Company is currently planning to order an additional $6 million in EADA over the course of the DSP. The EADA that the Company plans to order include, but are not limited to, the following categories:

- ***Wire and Cable*:** Distribution wire and cables are used to deliver electricity to our customers that take distribution-level service, and they may be located either above or below ground. This equipment is currently subject to supply chain challenges and long lead-times spanning 6 to 12 months.

- ***Line Hardware (e.g., fuses, arrestor, and insulators*:** Line hardware are components on the distribution system with various functions depending on the specific component. This includes protection from faults, connecting wire or cable segments, or isolating energized wires. The Company's need for this category of equipment is more than doubling from historical levels in some instances, and the manufacturers have unpredictable production delays. While the Company used to be able to procure this equipment within a matter of weeks, lead times for this equipment can now span multiple months.

- ***Distribution Transformers*:** Distribution transformers, which are used to step down the voltage from a distribution line to a lower voltage level so that it can safely serve a customer's premises, have been subject to heavy industry demand constraints since the pandemic, with lead times growing from what was typically four to six months to up to three years in some cases.

- ***Electrical Cabinets*:** Electrical cabinets are used to distribute power from along the distribution circuits and to transfer load as needed as well as to offer protection of smaller load sections. For this category of equipment, supply is not keeping pace with usage growth. Usage growth is up 50 to 150 percent on the high usage cabinets and 70 percent to 300 percent on the lower usage cabinets. Lead times for this category of equipment are currently over a year.

- ***Connectors*:** Connectors are electrical components that connect different systems and provide a reliable and low-resistance electrical path between hard wiring and flexible wiring. This category of equipment is currently subject to lead times of four to six months.

- ***Reclosers*:** This equipment is used to protect and isolate sections of the distribution circuit to limit the impacts of outages to customers. They are

[25] See § 40-2-132.5(4)(d)(VI), C.R.S.

also used for enhanced powerline safety settings to support wildfire mitigation efforts as well as used for larger DER interconnections and to improve customer reliability. This equipment is currently subject to long lead times ranging from six to seven months.

The Company purchases much of this equipment through established supplier arrangements, and the Company is limited in the quantities it can purchase each month due to industry-wide manufacturing capacity constraints. While it is also possible to purchase EADA on the open market, that option can be subject to higher costs and often longer lead times. The Company is working to renegotiate its supplier contracts to increase the amount of equipment it can procure and has contracted with additional suppliers, but these challenges of long lead times and limited manufacturing capacity are industry wide as demand for this equipment has been steadily increasing over the past several years. Based on these challenges, the Company has determined that it is prudent and necessary to order each of these categories of EADA to address long lead times and supply chain constraints. Without these advance orders, the Company is concerned that we will encounter project delays and related challenges that will undermine our ability to provide the distribution infrastructure that our customers and communities require in a timely and efficient manner.

ADDITIONAL INVESTMENTS SUPPORTING THE EVOLUTION OF THE DISTRIBUTION SYSTEM

In addition to the above budget which must be specifically provided by the DSP Rules, the Company is presenting costs that while not typically included in the Distribution Capital budget, are nevertheless important enablers of planning for and operating a modernized and evolving system. The following Capital and O&M projects are not included in the 2025-2029 distribution budget, but the Company is bringing them forward for GMAC recovery through this DSP consistent with SB 24-218. SB 24-218 provides that the Company can recover the costs associated with information and technology activities investments that enhance the distribution system's ability to meet State policy goals through the GMAC.

TECHNOLOGY SERVICES

To meet the evolving needs of our customers, implementing and leveraging new technologies has become nearly as important as the physical infrastructure and assets reflected by the categories in the distribution categories discussed above. Importantly, technology is a necessary foundation for providing better visibility into system operations, enhancing reliability, and maximizing the efficiency and useful lives of many types of assets. The projects reflected in table below and projects that meet the statute language and are included in the Company's Technology Services budget but are critical projects

that support providing more reliable and resilient electric service. These projects are discussed in additional detail in the Grid Modernization and Grid Innovation section.

Table 16: 2025 – 2029 Technology Services Budget ($Millions)

Category	2025	2026	2027	2028	2029	Total
Advanced Outage Management ("AOM")	$18	$24	$10	$0	$0	$52
Aggregator DERMS	$2	$2	$0	$0	$0	$5
Private LTE	$6	$6	$3	$0	$0	$15
Operational Technology Asset Monitoring ("OTAM")	$0	$0	$0	$0	$0	$0
Distributed Intelligence ("DI")	$1	$0	$0	$0	$0	$1
ADMS - PI Adaptor - Limited Deployment	$0	$0	$0	$0	$0	$0
Total Technology Services GMAC Capital	**$25**	**$30**	**$12**	**$0**	**$0**	**$72**

In addition to the capital budgets reflected above, the DSP budget also includes operations and maintenance ("O&M") costs associated with qualifying distribution activities. These amounts are largely attributable to additional internal and external labor that will be needed to support the implementation of this DSP, and lay the groundwork for future DSPs, as presented in the Company's Staffing Analysis. The DSP's O&M budget will also support stakeholder outreach efforts. The DSP's O&M budget is shown below:

Table 17: DSP O&M Budget

Category	2025	2026	2027	2028	2029	Total
Incremental Staffing	$3,594,638	$5,029,310	$5,898,585	$6,329,586	$6,519,474	$27,371,592
Community Outreach and Engagement (Non-Staffing)	$565,000	$605,000	$650,000	$600,000	$545,000	$2,965,000
Total GMAC Eligible O&M	$4,159,638	$5,634,310	$6,548,585	$6,929,586	$7,064,474	$30,336,592

LEVERAGING FEDERAL FUNDING TO REDUCE COSTS

The Infrastructure, Investment, and Jobs Act ("IIJA") and the Inflation Reduction Act ("IRA") provide an unprecedented national investment in clean energy and infrastructure, over $60 billion in energy and transmission related funds and more for broadband, transportation electrification and other infrastructure. In the months leading up to the passage of these laws, the Company worked with the Edison Electric Institute and other organizations to communicate the need for new energy solutions to achieve emissions reductions and improve grid resiliency while protecting costs borne by customers. The Company believes that this work influenced many aspects of the IIJA including its funding for advanced energy technology.

The Department of Energy ("DOE") has the responsibility for managing program funds from the IIJA and IRA through nationally competitive solicitations as well as state specific allotments through a formula approach. This includes funds for resiliency, transportation electrification, and distribution. State agencies (such as state energy offices, broadband offices, departments of transportation, and public utility commissions) have received approval by federal agencies to begin implementing their formula-based grant programs. As these and other funds are distributed, the Company will remain engaged with the Commission, Colorado Energy Office ("CEO") and other stakeholders.

Xcel Energy views pursuit and successful receipt of IIJA and IRA funding as an important strategic initiative to advance its system resiliency and emissions reduction objectives while managing costs and risks of new projects. Moreover, as part of the Distribution System Plan Settlement Agreement, in Paragraph 52, the Settling Parties recognized the potential value in seeking federal funding available to advance distribution-related investments for particular purposes, including grid modernization and resilience. For much of 2023, DOE was working through the process of evaluating concept papers and applications submitted to their new program offices in response to numerous Requests for Information and Funding Opportunity Announcements ("FOA"). In the second half of 2023, DOE announced funding awards for several Xcel Energy applications. In the first half of 2024, the Company has primarily been focused on funding negotiations with DOE for projects awarded last year and pursuing new grant applications. This pursuit has included multiple distribution focused applications and projects including:

Funding Grant & Projects	Full Award	Award Selection
GRIP Topic Area 1: Xcel Energy Wildfire & Extreme Weather Mitigation – Xcel Energy will implement a range of projects that enhance the grid's resiliency in the face of fires, severe storms, and other adverse environmental conditions to better protect lives, homes and forests while reducing and preventing power outages. This includes strategic distribution focused projects including undergrounding high risk distribution circuits, restoration response program for distribution lines, and community microgrids.	$100 million	**Selected for Award**
GRIP Topic Area 2: Xcel Energy Private LTE – Rapidly deploy an Xcel Energy Private LTE Network. Implement DERMS to improve visibility to grid operators and integration of DERs. Create a managed charging solution to support vehicle grid integration and proactively manage impacts of charging on the distribution grid to enable EV integration and grid operator's visibility.	$50 million	Not Selected for Award
DERMS-Boulder Prime Time VPP - Xcel Energy, The City of Boulder, University of Colorado Boulder and the National Renewable Energy Laboratory will integrate and coordinate diverse distributed energy systems (DES) and technology to perform various, scalable, and valuable grid functions to meet distribution and bulk system needs. This will inform future growing DES systems in successful frameworks for enabling and operating a clean energy future with diverse communities.	$12.7 Million	**Selected for Award** – see next section
GRIP TA2: Kevala - Flexible electric grid interconnection software tool for DERs – Xcel Energy will work with Kevala to develop a flexible electric grid interconnection software tool that can accelerate the adoption and interconnection of distributed energy resources ("DERs") including distributed generation, electric vehicles, and other beneficial electrification measures.	Xcel Energy -In-Kind	Not Selected for Award
EPRI – Multi-Regional Investments for Resilience At-Scale (MIRA) – Xcel Energy will work with EPRI to perform a pilot project of implementing a distributed energy resource management system (DER, DERMS) with the intent to provide flexible interconnection solutions to large DER generation customers and electric vehicle fleet managed charging. Additionally, Xcel Energy would utilize project funds to improve its grid model management capabilities with the outcome of increased model accuracy and automation for internal planning studies and public-facing DER hosting capacity analysis improvements.	$4.27 million	Not Selected for Award
Highland Fleet - Scaling Vehicle-to-Grid Integration Nationally (SVIN) – Xcel Energy will work with Highland Fleets and Denver Public Schools to deploy Vehicle to grid electric school bus projects and develop	$830,000	**Selected for Award**
DOE Interconnection Innovation Exchange (i2X) - This project received technical assistance from the Pacific Northwest National Laboratory. The goal was to create an end-to-end process**,** and best practices guide to implementing flexible interconnection, including a generic template of key interconnection and operational agreements between utilities and customers, to enable flexible interconnection. This is part of a broader i2X initiative to support efforts in the area of flexible interconnection standards and implementation.	National Laboratory Technical Assistance	Awarded and Completed in 2024

GRIP Round 2, Topic 1: Wildfire mitigation and Grid Resilience Portfolio for Xcel Energy – Xcel Energy seeks DOE funding to implement a portfolio of grid resiliency projects focused on wildfire risk reduction and innovative transmission and distribution upgrades; including community focused resiliency microgrids and installing new sectionalizing protective equipment devices, communications devices, and substation relay upgrades.	$100 million	Not Selected for Award
GRIP Round 2 Topic Area 2: Grid Edge Solutions for Resiliency and DER Networking - Implement a suite of innovative grid edge technology solutions and infrastructure to enhance secure communications, grid operator visibility and control of Distributed Energy Resources (DER), and power system reliability and resilience. Achieve through a portfolio of projects focused on Private Long-Term Evolved Network (PLTE), Distributed Energy Resource Management (DERMS), and Underfrequency lad shedding (UFLS) to decrease the possibility of largescale blackouts across Xcel Energy's 8 operating states.	$100 million	Not Selected for Award
Connected Communities 2.0 - IBACOS, E3, Tierra, NREL, and Xcel Energy together will study and demonstrate the optimal control of hybrid heat pumps in the residential retrofit market in the Denver Metro region. Project aims to demonstrate how this wave of heat pumps can be controlled to limit electric system impacts, minimize emissions, benefit customers, and support community-wide resilience.	In-Kind	Awaiting DOE Decision
The DER Cyber Secure and Operationally Reliable Gateways (CYBORG) is a DOE funded project. The project's objectives are to research, develop, test, and demonstrate top priority cybersecurity features for DER. The state of the technology will be advanced through commercial partners, public specs and open-source software. EPRI is the prime recipient and the overall project manager. Subrecipients are ASE Systems, WhyGrene, MITRE. Xcel Energy is a partner in this project that will be involved developing use cases and technical requirements, and provide demonstration site for DNP3 based open source Implementations.	Partner with zero funding	**Selected for Award**
The Solid-State Transformer project is partially funded through a DOE grant. In this project we will develop and test an advanced distribution step-down transformer that uses solid-state electronics to increase the capabilities of traditional step-down transformers. The solid-state transformer provides more control over power flow and power quality to help integrate increasingly complex customer loads such as DER, EV chargers, and nonlinear power supplies. EPRI is the prime recipient and the overall project manager, and Xcel Energy is one of the subrecipients. Xcel Energy will have the opportunity to pilot a beta unit in the 3rd year of the project, which would come at our own additional cost if we choose to pilot.	Up to $125 thousand, with a potential of $100 thousand if Company pilots a unit	**Selected for Award**

Prime Time Virtual Power Plant ("VPP")

The U.S. DOE Office of Clean Energy Demonstrations ("OCED") on September 30th announced up to $50 million in funding for three clean energy projects that help the U.S. develop a more responsive, resilient, and economical electric grid. These projects span across Colorado, Massachusetts, and Virginia to support the demands of an increasingly electrified nation filled with electric vehicles ("EV"s), advanced industrial operations, smart technologies, and sizeable energy storage. These projects are part of OCED's Distributed Energy Systems ("DES") Demonstrations Program[26], which aims to support diverse, scalable, replicable clean energy projects needed to build safer, climate resilient communities, while helping the nation reach President Biden and Vice President Harris' ambitious clean energy and climate goals.

The Prime-Time Virtual Power Plant project—led by Xcel Energy - would develop and integrate a virtual power plant ("VPP") in the Boulder, CO area. Boulder is home to several federally funded research labs, the University of Colorado Boulder, and a concentration of advanced technology companies. This project would explore the aggregation of the DERs of participating consumers to balance, optimize, and shift electrical loads, minimizing upgrades and costs for customers. The project could help Boulder reach its 100% renewable electricity goals by 2030. The implementation of the proposed VPP offers a scalable solution that can be applied to the rest of Xcel Energy's multi-state grid, providing operational flexibility to enable the power system to respond efficiently to changes in supply and demand that could be further replicated across the industry.

Selection for award negotiations is not a commitment by DOE to issue an award or provide funding. Before funding is issued, DOE and the selectees will undergo a negotiation process, and DOE may cancel negotiations and rescind the selection for any reason during that time. In the Company's experience this process can take up to a year. If awarded, OCED will evaluate these projects through a phased approach to project management that includes "go/no-go" decision points between each project phase where DOE reviews and evaluates implementation progress, including community benefits.

As the Company enters award negotiations with DOE, the Company will finalize project budget, milestones, and anticipated outcomes. This budget is likely to be a mix of already allocated funds from existing projects, as well as incremental new funding for project specific.

[26] https://www.energy.gov/oced/distributed-energy-systems-demonstrations-program

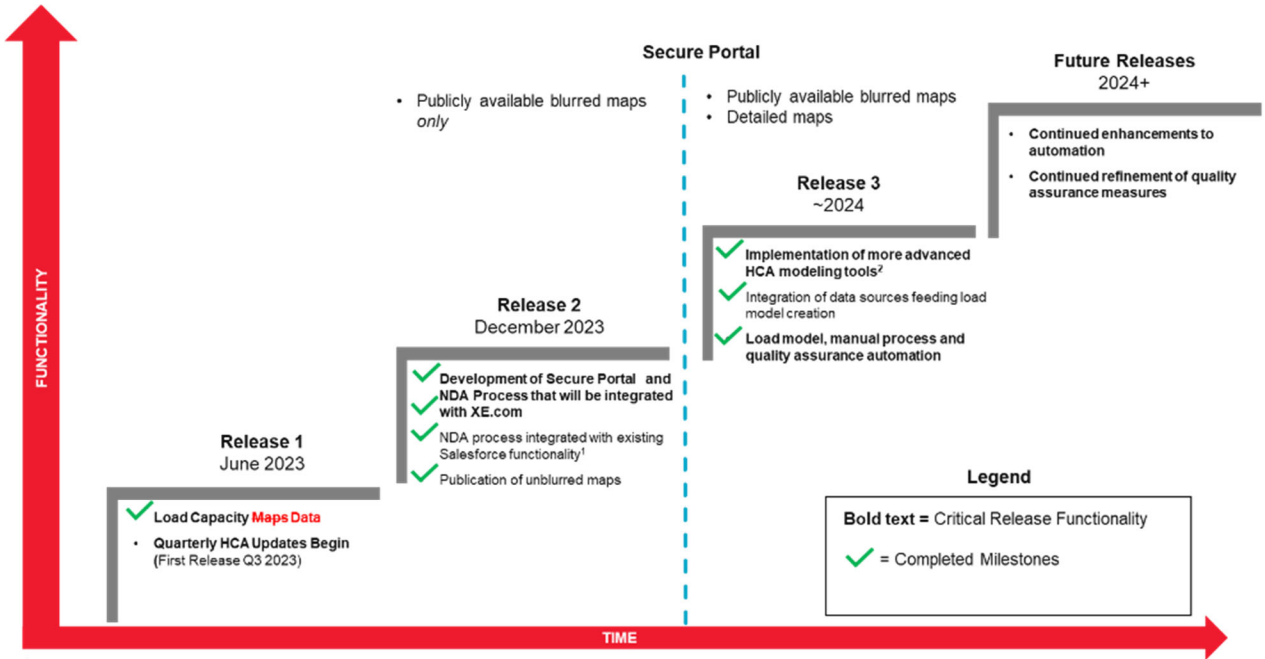
X. Enhancing the Customer Journey

The ways our customers interact with the grid are changing. As a result, the Company recognizes that new tools and data sources can help inform parts of the customer journey – whether that be interconnecting rooftop solar, connecting EVs and EV charging, or supporting the energization of new housing. This section describes the tools, processes, and improvements the Company has made and discusses how this evolution will continue.

HOSTING CAPACITY ANALYSIS AND RELATED TOOLS

Since the development of distributed generation hosting capacity maps in 2017, the Company has continually improved its Hosting Capacity Analysis ("HCA") methodology to better support stakeholders and DER developers. The Company has made significant strides in implementing its Hosting Capacity Analysis Roadmap presented in the inaugural Distribution System Plan. The roadmap, shown in Figure 46 below, has made more information available to stakeholders to better facilitate DER and load interconnections to the distribution system. The green checkmarks below indicate where the Company has met the roadmap objectives.

Figure 46: HCA Roadmap from 2022 DSP Filing



[1] Integrating the secure portal with existing NDA practice and login credentials (i.e. signal sign-on) is not critical to establishing a secure portal, however the Company believes this integration could enhance the customer experience.

[2]The Company is exploring the use of other HCA modeling tools.

The Hosting Capacity Analysis Roadmap contained six foundational enhancements that are critical to improving the customer experience when it comes to adding new technologies to our distribution system. These six elements have either been delivered or are in the process of being implemented.

1. Secure Web Portal
2. Detailed Hosting Capacity Maps
3. Load Hosting Capacity Analysis
4. Enhanced Distribution Modeling Tools
5. Process Automation and Enhanced Data Quality Assurance
6. Quarterly Hosting Capacity Analysis Updates

The Company anticipates that the improvements set forth in this roadmap will allow developers and customers to better understand the distribution system and provide an initial indication of where to best site their projects. The enhancements and automation will provide developers with a better understanding of the distribution system with more up-to-date information. This will not only aid DER developers, but it will also help guide customers to understand the limitations of the distribution system at their specific locations.

Secure Web Portal and Detailed Hosting Capacity Maps

The Company has developed and implemented a secure web portal to provide registered users access to view detailed generation hosting capacity maps, view tabular attachments for generation and load hosting capacity results, and the Grid Needs Assessment filed in the most recent Distribution System Planning filing. The portal requires users to register and sign a Non-Disclosure Agreement (NDA) to view the sensitive information contained behind the login. Once approved, users gain access to the detailed generation maps and the confidential attachments. The detailed generation maps are available to stakeholders who complete the submission process, while the heat map hosting capacity maps will continue to be available to the public.

The heat map (sometimes known as “blurred”) hosting capacity maps provide a good initial high-level indication of available hosting capacity to interconnect distributed generation in a certain area and can be found on the Company’s Renewable Energy website[27]. Due to confidentiality restrictions, the detailed version is only available through the secure portal, which can be accessed through the Company’s building and

[27] Hosting Capacity Map | Renewable Developer Resources | Xcel Energy

Remodeling webpage[28]. A screenshot of the user experience for the detailed hosting capacity map is presented as Figure 47 below.

Figure 47: Confidential Screenshot of Detailed Hosting Capacity Analysis Maps



Once the user navigates to the Detailed Hosting Capacity Map page, they can view the tabular results for both load and generation hosting capacity and the Grid Needs Assessment attachment filed in the more recent Distribution System Plan filing.

The detailed maps provide more insights into the distribution system and can provide developers with more certainty around how their project may interconnect to the distribution system.

The Company also provides a cost sheet for common distribution and substation upgrades to assist developers in better understanding upgrade costs that their project would incur. Based on the Threshold in Violation information set forth in the popup menu on the HCA map, developers can estimate some of the costs that may be incurred if interconnection is pursued at a specific location on the distribution system. Feeders that violate Rule 3033, also known as the "15/15 rule[29]," will not be mapped behind the secure

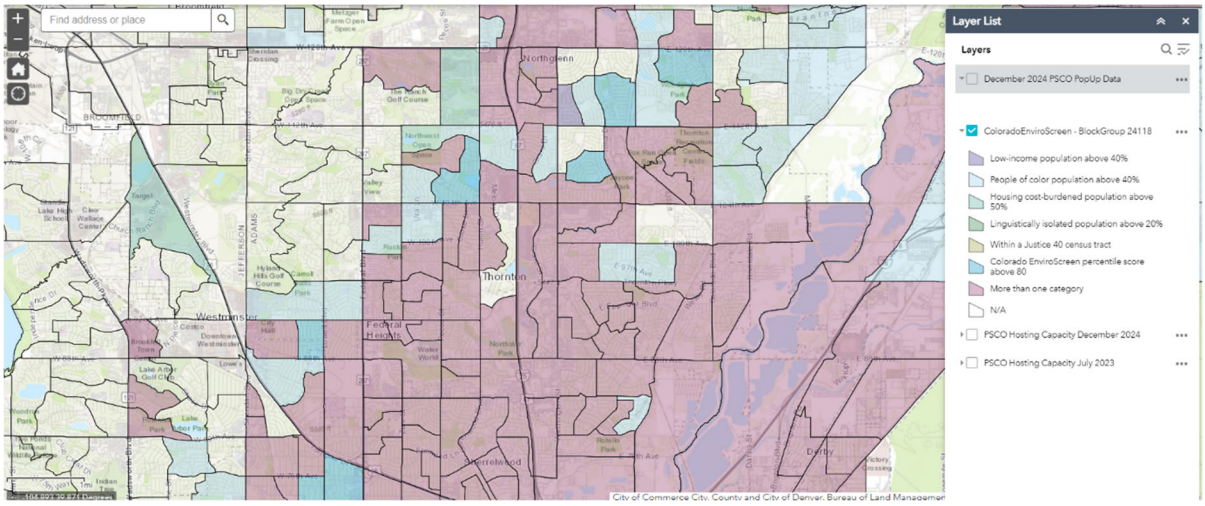
[28] Building and Remodeling | Partner Resources | Xcel Energy
[29] The 15/15 Rule states that when sharing customer information in aggregate, a particular aggregation must contain at least fifteen customers; and, within any customer class no single customer's customer data or premise associated with a single customer's customer data may comprise 15 percent or more of the total customer data aggregated per customer class to generate the aggregated data report.

portal, in alignment with privacy protection under Rule 3033 and the process for the detailed maps.

The Company recently conducted a survey regarding this interface. The results showed that approximately 55% of users found the secure portal and the detailed HCA maps helpful and increased their efficiency. Based on some of the comments, this approval rating will increase as more frequent map publications are released.

The Company also made enhancements to its public blurred HCA maps. Users of the public HCA maps can toggle different layers on and off within the map viewer, shown in Figure 48. Previous HCA publications are available, in addition to a DI Community layer generated from the Company's EnviroScreen tool.

Figure 48: Public Hosting Capacity Map DI Community Layer



Secure Portal Usage

The Company reviewed the data based upon user access requests since March 27, 2024. Overall, the usage statistics, when coupled with the recent survey, seem to suggest there is less interest in the detailed mapping than initially suggested. A comparison of usage statistics for the same time period for the heat map view of hosting capacity is provided below. While the Company cannot definitively say the reasons behind this, one potential reason is because users appear to be finding value in the more detailed tabular data that is available as a pop up on the heat map hosting capacity map.

Table 18: Comparison of Unblurred HCA Map to Blurred Map Usage Statistics from March – December 2024

	Detailed Hosting Capacity Maps	Heat Map Hosting Capacity Maps

Number of NDAs Submitted	99	N/A
Number of NDAs Approved	89	N/A
Users to the Detailed Hosting Capacity Maps	48	3,303

Load Hosting Capacity Analysis

The Company first performed load hosting capacity analysis for the Colorado distribution system in Q2 2023. The Company worked to develop the methodology, documentation, processes and data inputs, and quality assurance measures to ensure an accurate analysis. The Company has refined this process to be in alignment with Minnesota and Colorado load hosting capacity requirements. In Q2 2024, the Company began conducting hosting capacity analysis for both load and generation and has published the results to the Company's secure web portal. The generation hosting capacity results have been published as public facing heat map maps, as detailed maps behind the secure portal, and in tabular form. And now the load hosting capacity analysis results have been uploaded in tabular form behind the secure portal.

Web portal users have found the tabular hosting capacity results to be useful, with 70% of surveyed users stating that they are helpful and over 35% said that they improve their efficiency.

Load Hosting Capacity Mapping

In accordance with § 40-2-132.5(5)(d), C.R.S., the plan is required to include "detailed mapping of distribution hosting capacity with appropriate safeguards to protect critical infrastructure, as determined by the Commission." The Company is requesting Commission approval to provide this data on a Highly Confidential basis to the Commission and authorized parties that have signed an appropriate Highly Confidential NDA.[30] As proposed, secure access will be provided through an ESRI ArcGIS Online interface if the authorized party has that platform, or, alternatively, Company-facilitated viewing. The Company has a responsibility at both the state and federal level to safeguard information regarding critical infrastructure, and physical and cybersecurity attacks on the Company's electric facilities could cause widespread disruption to the electric grid.

Quarterly Hosting Capacity Analysis

The Company is in the process of implementing and upgrading our load flow software tools that will enable more frequent HCA map publication through a sustainable and

[30] A Motion seeking highly confidential treatment is being submitted with our Plan filing and specifies the limited access the Company is requesting to this highly sensitive data.

repeatable process. While the Company had originally anticipated producing quarterly generation HCA maps by the end of 2023, the Company expects quarterly HCA maps to be published beginning in Q2 2025 once CYME is operational.

Load Flow Modeling Tool to Support More Frequent Hosting Capacity Updates

As discussed in previous portions of this section, the Company is working to automate the model building, analysis and quality assurance measures when it comes to distribution system modeling. This will allow the Company to publish more frequent hosting capacity map updates by reducing the number of manual steps performed in the process. The automation of the model building process is discussed below, along with automation of the hosting capacity analysis.

Automate the Model Building Process

As mentioned previously, the Company is working with Eaton (the developer of the CYME software) to develop a custom Gateway tool that will compile and fill distribution load models for all Xcel Energy distribution systems. What used to be a manual process to build models, including compiling data from multiple sources, validating customer loading, and using engineering judgment to complete a model to be used in an analysis will be automated through the Gateway established by the Company, with a monthly refresh process for distribution feeder models. This process will allow distribution modeling engineers to streamline the model refresh process for the entire distribution system. The goal is a maintained production database of validated loan flow models could be automated against, which will enable further automation.

Automate Hosting Capacity Analysis

The Company is developing the algorithms and processes to automate generation and load hosting capacity analyses for the entire distribution system. This capability will be operational once the Load Model database has been established, as specified in Section V. The first case that the Company is implementing is the automation of HCA./ The Company is working to develop the python scripting that will enable the automation of both load and generation hosting capacity analyses. The automation of hosting capacity also includes an updated web applicator that better streamlines the conversion of the hosting capacity results into a final map product for both the heat map and detailed maps. The Company anticipates that the monthly model refresh with the enhanced data validation and quality assurance steps will allow for more frequent hosting capacity updates beyond a quarterly cadence.

Streamline Quality Assurance Process

To ensure that the hosting capacity results are accurate, the Company has enabled numerous quality assurance measures throughout this process. As previously discussed, there are assurance measures built within the model building process. The Company is working to develop the python scripting that will enable the automation of those quality assurance steps, including the flagging of feeders with zero hosting capacity, with significant changes in hosting capacity, and with changes in limiting elements. With more frequent and automated analyses and quality assessments, more resources can be allocated towards more advanced validation methods, which continue to be explored and evaluated. The Company has also implemented quality insurance measures throughout the hosting capacity analysis as well as after the results are produced.

Feeder Queue Report

In the 2022 Distribution System Plan, the Company was directed to provide a publicly available monthly feeder DER Queue report. The report was modeled after a similar report prepared by the Company's affiliate, Northern State Power-Minnesota. By making this information publicly accessible, we aim to enhance transparency and provide stakeholders with valuable insights into our feeder DER queue status.[31] This initiative will support informed decision-making and foster greater trust and collaboration with our stakeholders.

Respondents to the Company's Hosting Capacity and Web Portal Survey have provided favorable feedback related to this effort. Many survey respondents were aware of the DER Queue report and knew where to find it. Additionally, several respondents reported that the DER Queue report was helpful and either improved or greatly improved the ease and efficiency of the interconnection process. When asked to explain how the DER Queue report increased the ease and efficiency of the interconnection process, one respondent mentioned that the report led to "transparency and visibility into the available capacity for development, including the limiting factors for interconnection capacity." Another respondent noted that the "queue report offers information about projects in a similar vicinity and can be used as a guide to estimate how long it may take for a new project to be reviewed under Xcel's sequential review process."

Field Verification of HCA Results

As part of the 2022 Distribution System Plan Settlement Agreement, the Company agreed to validate HCA results of five different areas across the system. In an effort to cover the state, a field crew member from five different service centers selected a feeder and reviewed the Enterprise Resource Planning Identifier ("ERP ID"). This ID is used to track and manage various aspects of the Company's assets including but not limited to asset details, maintenance records, operational data, and GPS coordinates. The overhead

[31] Interconnection | Renewable Developer Resources | Xcel Energy

conductors were field verified and compared against the GIS values to see if the records are accurate as this information is used in the Company's HCA modeling and analysis. A summary of the findings is included in Table 19 below.

Table 19: Hosting Capacity Analysis Field Verifications

Location	Equipment Type	Wire #1	Wire #2	Wire #3
Location #1 (Arvada)	**Equipment Type**	# 2 ACSR	795 AAC	795 AAC
	GIS Check	Matched	Matched	Matched
Location #2 (Evergreen)	**Equipment Type**	1/0 ACSR	1/0 ACSR	
	GIS Check	Matched	Matched	
Location #3 (Greeley)	**Equipment Type**	#2 ACSR		
	GIS Check	Mismatch		
Location #4 (Denver)	**Equipment Type**	#2 ACSR	#2 ACSR	#2 ACSR
	GIS Check	Matched	Matched	Matched
Location #5 (Lakewood)	**Equipment Type**	# 6 CWC	# 6 CWC	# 2 ACSR
	GIS Check	Matched	Matched	Matched

DER INTERCONNECTION PERFORMANCE

On July 31, 2024, the Company filed its latest interconnection report pursuant to Commission Rule 3853(q). The reporting period covered interconnection activity from January 1, 2024, through June 30, 2024, (the "Current Reporting Period") as well as activity during the Previous Reporting Period (July 1, 2023, through December 31, 2023) and the Annual Total for 2023. The report included processing times for Pre-Application Data Reports ("PADRs"), Level 1, Level 2, and Level 3 study reviews. The report includes interconnection applications for both customer-sited Distributed Energy Resources ("DERs") as well as Community Solar Gardens ("CSGs").

For the first time, the Company reported on metrics related to the Interconnection Refund Mechanism and Performance Incentive Mechanism ("PIM") for the time period between April 11, 2024, and June 30, 2024.

The Company continues to process applications at a pace that is nearly always meeting or outperforming the required Commission timelines. The Company continued to improve its processing time for the completion of PADRs, processing these reports in a mean average of 10 days as compared to 12 days in the Previous Reporting Period. The Company also greatly improved processing times for Level 3 reviews, completing reviews in a mean average of 28 days as compared to 37 days in the Previous Reporting Period, even as the number of Level 3 reviews more than doubled.

As reported in previous interconnection reports, the Company worked in 2023 to improve internal processes to shorten Level 1 approval timelines and, while the Company continues to observe and adjust these efforts, these shortened timelines for Level 1, as well as Level 2, reviews have largely continued in the Current Reporting Period.

Evaluation of Substation Bi-Directionality

As a part of the 2022 Distribution System Plan Settlement Agreement, the Company agreed to evaluate the costs, benefits, equity and impediments to installing a substation with technology that would enable bi-directional power flow, such as 3V0 protection. This equipment is required by the Company when the reverse power flow through the substation transformer exceeds a certain threshold. The Company requires the installation of 3V0 when the reverse power flow through that asset is identified during an interconnection study. Installing 3V0 enables additional DER to interconnect on the distribution system supported by the transformer where the equipment is installed and helps ensure that the system will continue to operate safely and reliably as more generation resources interconnect.

The substation upgrade requires the installation of capacitive-coupled voltage transformers, relaying and control wiring to be installed within the substation, which can

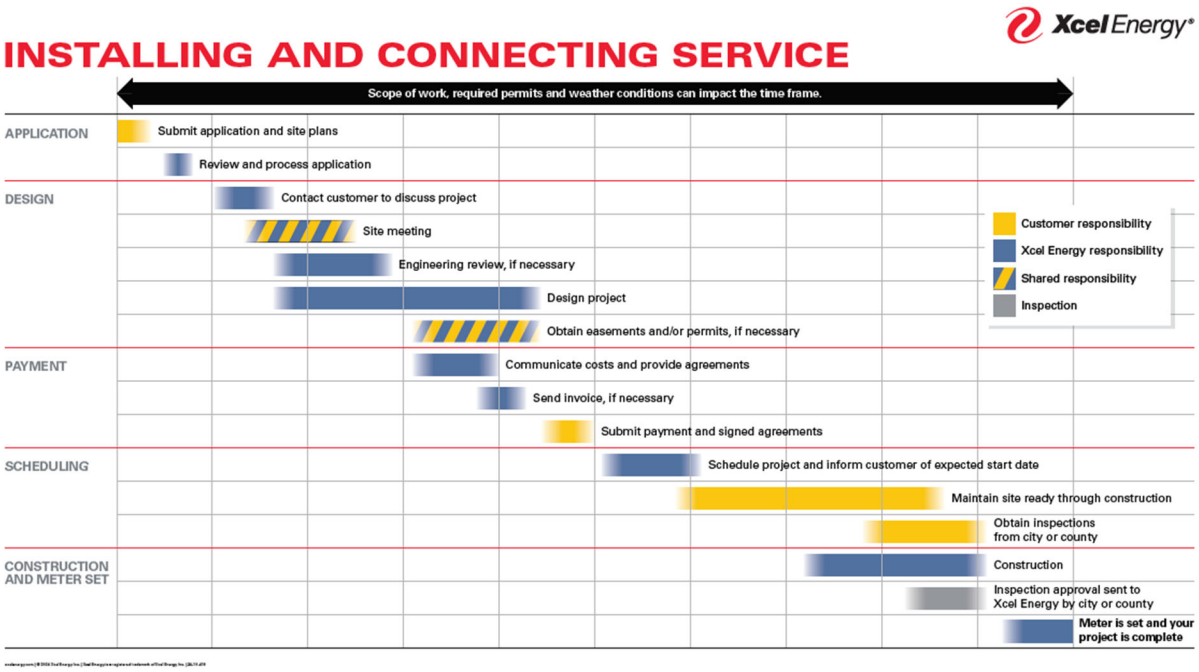
be challenging to construct if the initial substation design did not factor the equipment into the overall layout.

The Company evaluated nine new substation banks that are currently being designed to determine the costs of installing the 3V0 equipment during the substation construction rather than later on when a DER application is reviewed. The Company found that the average indicative cost to install the equipment after a substation has been constructed is approximately $430,000, whereas during the construction of a substation transformer it is approximately $350,000, approximately a 23% savings. The Company believes that in certain areas, it may make sense to proactively install 3V0 protection equipment to enable more hosting capacity for DER interconnections. The Company is also evaluating whether to incorporate 3V0 protection into its standard substation design, as it did with voltage supervisory reclosing (“VSR”) protection upgrades, which now comes standard for all new distribution feeders. Also, per the terms of SB 24-207, the Company anticipates working with stakeholders and proposing an interconnection upgrade cost-sharing framework in January 2025.

IMPROVEMENTS TO THE LOAD ENERGIZATION PROCESS

The Company currently fulfills requests to serve new or expanded load through a service application process. When a distribution extension or capacity upgrade is needed to fulfill the service request, the energization process generally follows the steps outlined in Figure 49 below. We understand that making this process more transparent and accessible to our customers and other stakeholders is a critical item.

Figure 49: Service Application Request Process



There are varying levels of complexity associated with connecting new loads to the distribution system. Similar to the DER interconnection process, the Company's energization process is delineated into three levels of complexity. As noted in the figure above, there are sub-processes in the overall process that are the sole responsibility of the Company while other steps are the responsibility of the customer seeking interconnection. While the Company is working to develop more comprehensive and detailed energization tracking consistent with the requirements of SB 24-218, generally speaking, projects which require network reinforcements (i.e. areas of the system where a formal load request may exceed available capacity) are the most complex and take longer to complete.

Regardless of scope, for projects requiring distribution system upgrades, there are various agencies/municipalities that issue permits and crossing agreements required to perform work. Most commonly this is subsurface utility engineering required to work in right of ways. Obtaining these permits can sometimes take weeks or months depending

on the specific project and area. When projects require these reviews and permits, the associated timing is no longer under the sole control for performance measurement. Consistent with SB 24-218's requirement that energization performance be measured for steps that are solely within the utility's control, the Company believes that performance on fulfilling service applications is most accurately evaluated in the context of projects that do not require such reinforcement, and associated permitting approvals, to move forward.

This Plan includes significant proactive investments in bolstering our distribution system capacity, and we expect that having this increased capacity already available when customers initiate service requests will go a long way towards reducing the number of formal service application requests that trigger network reinforcements and the associated lead times from these larger, more complex projects.

Through Commission Proceeding No. 23M-0464EG, the Company has been engaging with the Commission, key stakeholders, and our customers and communities on how we can improve our service application and broader energization process to create a more predictable and positive customer experience. While broad changes to such a high-volume and resource-intensive process will take time to implement, the Company is making strong progress on several of the Commission's recommendations through that proceeding.

Maintaining Consistency Across Service Application Forms

The Commission has expressed concern about potential inconsistencies between the PDF version and the interactive online version of our service application, and the Company has implemented an updated service application that is consistent across mediums and comprehensively captures the categories of data needed to evaluate the need for supporting distribution infrastructure.[32]

Standardizing the Language and Content for Conceptual Capacity Checks

Consistent with Commissioner Gilman's recommendation in Proceeding No. 23M-0464EG for capacity checks, the Company is also working to develop standardized language for all conceptual capacity check responses to help ensure that our customers are adequately informed about the inherent limitations of conceptual capacity checks. One of these limitations is that the remaining capacity available to serve prospective load remains subject to change based on evolving system conditions as the Company continues to fulfill other service requests. The Company does not reserve distribution capacity for a development until the customer completes a formal request. The updated language will advise customers that the results of a conceptual capacity check cannot be

[32] https://co.my.xcelenergy.com/s/partner-resources/build-remodel/docs-forms

relied upon to determine whether additional distribution infrastructure will ultimately be needed to fulfill a future service request or the corresponding cost of such infrastructure. The Company is also working to further develop self-service content on xcelenergy.com and more standardized processes for conceptual capacity checks.

Capacity Reservation Proposal Consideration

In Proceeding No. 23M-0464EG, Denver proposed the concept of a capacity reservation policy in an effort to help create additional certainty for new loads connecting to our system. This proposal was also submitted to the Company through the third-party solicitation pilot solicitation process. The Company appreciates Denver's proposal, but will not be moving forward with implementing this concept as proposed. We believe that some of the near-term initiatives the Company is taking related to making the customer energization process more transparent and consistent will mitigate some of the challenges customers have encountered in the past. Further, tracking and enforcing such a policy is a complex undertaking. In addition, the investments the Company is proposing in this plan will unlock approximately 3,000 MW of new capacity, with a good portion of that capacity benefitting the Denver metropolitan area.

Limited Interconnection Costs and Exploring Alternative Connection Strategies

The Company has heard from our customers and communities that the costs associated with distribution upgrades can present a significant barrier to beneficial electrification and the adoption of DERs, which are both critical state energy policies. As described further below, Public Service has implemented customer cost caps for certain distribution upgrades.

As we discuss in the Grid DERMS section of the DSP, we are also beginning to explore use case for Flexible Connections for certain types of load. This is in addition to the ongoing work for Flexible Interconnection for Distributed Generation, which the Company has been working on with interested DER developers since the last Distribution System Plan.

PROGRESS OF ENERGIZATION TIMELINE DATA COLLECTION

The Company understands the need for improved data and transparency around our performance on energization, and consistent with the Commission's recommendations and SB 24-218, the Company has commenced a data gathering process, which has required extensive coordination and dedicated efforts among several departments, as described below

In accordance with SB 24-218, the Company has commenced a data collection process to inform future energization timelines through measurement of counts and timelines for

formal load and energization requests. In commencing this data gathering process, the Company has been working to identify the milestones in the energization process that can be reliably tracked, as well as certain limitations in currently available data.

One of the key limitations is that the Company's SAP system, the software platform the Company uses to conduct several key functions in the energization process, is not currently able to distinguish between the time it takes the Company to complete elements of the energization process that are within its control, and the time that the Company must wait for information or action from a service applicant, permitting authority, or other entity, in order to proceed further.

Given these limitations, the Company anticipates that it may need to implement a new technology solution to enable the Company to comprehensively and reliably track the timing of each step in the energization process that is within the Company's control, as well as to create an integrated application experience for customers seeking interconnections of DERs in conjunction with the energization of load in accordance with SB 24-218. Several departments and teams are currently working to determine the resources and technology needed to address the new requirements under SB 24-218, recognizing that developing an appropriate solution is a complicated undertaking.

Currently measurable milestones in the Company's load energization process include: 1) date from receipt of the service application (once the customer has provided all of the necessary information) 2) the time it takes for the Company to schedule necessary distribution projects to support the service request; and 3) the time elapsed from the start of construction until meter set and/or energization. A cross-disciplinary team is currently working to ensure consistent processes for tracking these steps and the reliability and accuracy of corresponding data. Once that process is complete, the Company will work to further refine and isolate the steps of the energization process that are within its control to enable the Company to track its performance on energization timing over the next Distribution System Plan, and ultimately be held accountable for its performance in future Distribution System Plans. The Company recognizes that energization timelines are a strong focus area for customers and our communities, and further that energization metrics will become part of the GMAC performance screen mechanism in the next Distribution System Plan.

INCREASING ACCESS TO ENERGY USAGE DATA

In compliance with Decision No. C24-0815 in Proceeding No. 23A-0471E, the Company provides the following information related to how it makes customer meter data available to customers or authorized third parties.

Table 20: Customer Data Elements

	Type(s) of Data	Frequency of data provided (15-minute, one-second, etc.)	Whether the data is raw[33] or processed (i.e., estimated)
Green Button Download	• XML file of 15-minute interval data (kWh)	• 15-minute interval data	• Raw
Green Button Connect	• XML file of 15-minute interval data (kWh)	• 15-minute interval data	• Raw
My Energy Connection	• One-second interval data (watts) • Daily, weekly, monthly line graphs for current and previous periods (kWh and $); shows Time of Use periods for daily view, if applicable • Customer's current rate (if on TOU, peak period name, time range, and dollar amount displayed) • Total electric energy usage and estimated cost up until the most recent 15-minute interval (with comparison to previous day's usage at same time) (kWh and $)	• One-second intervals • Daily, weekly, monthly data (current and previous) • Total energy usage and estimated cost for day (midnight to current time)	• Raw • Estimated[34] (daily, weekly, monthly data)
Xcel Energy Mobile App	• Bar graph and table view of invoice level data (kWh) • Link to My Energy Portal available within app.	• Monthly billing period data with TOU periods	• Invoiced[35]
Xcel Energy Web Portal	• Bar graph showing billing period (annual), billing period (current), monthly, daily, hourly, 30-min, and 15-min interval data (kWh and $) • Shows Time of Use periods, if applicable • Includes additional lines within graph to show rainfall, temperature, and weather	• Billing period (annual), Billing period (current), monthly, daily, hourly, 30-min, and 15-min interval data	• Invoiced • Estimated (monthly, daily, hourly, 30-min, and 15-min interval)
Third-Party Applications via Xcel Energy Launchpad	• VAh Delivered/Received Apparent Power • VARh Delivered/Received Reactive Power • Max Demand Delivered/Received Maximum sustained • kW over a billing interval	• One-second intervals (watts) • Total kWh since smart meter was installed (customer generated) • Total kWh since smart meter was installed (grid generated) • VAh Delivered/Received Apparent Power	• Raw

[33] The Company defines “raw” data as those data elements extracted directly from the meter and unprocessed for errors within the Company’s back-office systems.
[34] The Company defines “Estimated” data as data that has gone through initial processing in the Company’s back-office systems but has not been presented in a bill.
[35] The Company defines “Invoiced” as the fully processed and reviewed data used to calculate a customer’s bill.

	• Powerfactor Real Power / Apparent Power • TOU Delivered/Received power used/generated in each tier • Load Profile, Utility defined interval measurements • Wh, VAh, VARh (intervals only)	• VARh Delivered/Received Reactive Power • Max Demand Delivered/Received Maximum sustained • kW over a billing interval • Powerfactor Real Power / Apparent Power • TOU Delivered/Received power used/generated in each tier • Load Profile, Utility defined interval measurements • Wh, VAh, VARh (intervals only)	
Customer Care	In the event a customer does not wish to use one of these solutions, they also have the option to obtain their usage information in paper form by contacting Customer Care.		

Decision No C24-0815 also requested the Commission to provide, "[t]he specific steps the customer must go through to access and/or authorize sharing of data, including available educational materials or technical support, as well as any marketing the Company has performed to notify customers of these steps."[36] The Company provides the educational and technical materials via hyperlink below. Generally, customer facing educational information is made available to customers through the Company's website and periodic marketing emails.

i. Green Button Download Process Document:
   - https://xcelenergy.sharepoint.com/:w:/r/sites/GreenButtonConnectMyData/Shared%20Documents/General/Xcel%20GBC%20Web%20Docs/Green%20Button%20Download%20Process%20Document.docx?d=w16b542a2eaee4212a4d392fa8f1c25f5&csf=1&web=1&e=FI6Gvc

ii. Green Button Connect Process Document:
   - https://xcelenergy.sharepoint.com/:w:/r/sites/GreenButtonConnectMyData/Shared%20Documents/General/Xcel%20GBC%20Web%20Docs/Green%20Button%20Connect%20Process%20Document.docx?d=w0ee5c9a4afe64975ba5abad068ca3628&csf=1&web=1&e=3fZ09g

iii. My Energy Connection:
   - FAQs: https://xcelnew.my.salesforce.com/sfc/p/#1U0000011ttV/a/8b000003KGRp/RHUuXvwcSPy8ovLbK4XHGJiE8i8Txz_5.aemDZ731a4
   - Enrollment Guide: https://www.xcelenergy.com/staticfiles/xe-responsive/Marketing/23-06-

[36] *See,* Paragraph 46 subpoint 3(d) of Decision C24-0815.

619%20My%20Energy%20Connection%20Enrollment%20Guide_P1%20(1).pdf

- User Guide: https://www.xcelenergy.com/staticfiles/xe-responsive/23-09-511_MyEnergyUserGuide_P04.pdf
- Website: https://my.xcelenergy.com/s/billing-payment/energy-insights

iv. Xcel Energy Mobile App

- Google App Store Link: https://play.google.com/store/apps/details?id=com.xcelenergy.mec
- Apple App Store Link: https://apps.apple.com/us/app/my-energy-connection/id6446288880

v. Xcel Energy Web Portal

- My Energy Portal Process Document: https://xcelenergy.sharepoint.com/:w:/r/sites/HomeAreaNetwork/Shared%20Documents/General/My%20Account/My%20Energy%20Portal%20Process%20Document.docx?d=wa084ce885e9944edae1a50171a04e1a2&csf=1&web=1&e=qkXe43

vi. Third-Party Applications via Xcel Energy Launchpad

- Xcel Energy Launchpad Process Document: https://xcelenergy.sharepoint.com/:w:/r/sites/HomeAreaNetwork/Shared%20Documents/General/03%20-%20SDK/SEQ1.%20Enrollment,%20Provisioning,%20Licensing/Xcel%20Energy%20Launchpad%20Licensing%20and%20Provisioning.docx?d=w8e3b8f3a60244514a62557046c762a6e&csf=1&web=1&e=LQ7XAb

Finally, Decision No. C24-0815 requested the Company to provide information regarding "[a]ny limitations due to Public Service's or their vendors' or contractors' design or implementation of the solution that prevent a potentially eligible customer from being able to use it, including but not limited to limitations on the number of accounts, devices, meters, Internet bandwidth, etc."[37] Table 21 below provides the participation requirements for each of the data sharing processes the Company offers. Table 21 below further provides information regarding the "[c]urrent uptake of each solution as compared to customers that potentially would be eligible to use that solution."[38]

[37] *See*, Paragraph 46, subpoint 3(e) of Decision No. C24-0815.
[38] *See*, Paragraph 46, subpoint 3(f) of Decision No. C24-0815.

Table 21: Participation Requirements for Data Sharing Processes

	Eligible Customer Types	Advanced Meter Required?	"In-Home" Device Required?	Network (i.e. wi-fi, cellular, etc.) Connection Required?	MyAccount Registration Required?	Application Download Required?	Multiple Account/Address Restrictions?
Green Button Download	Residential only	No	No	Yes	Yes	No	No
Green Button Connect	Residential only	Yes	No	Yes	Yes	No	No
My Energy Connection	Residential only	Yes	No	Yes	Yes	Yes	Yes, at this time
Xcel Energy Mobile App	All customers	No	No	Yes	Yes	Yes	No
Xcel Energy Web Portal	All customers	No	No	Yes	Yes	No	No
Third-Party Applications using Xcel Energy Launchpad	Residential Only	Yes	Potentially, subject to third-party requirements	Yes	Yes	Potentially, subject to third-party requirements	Yes, at this time

Table 22: Current Participation in Data Sharing Processes

	Total Eligible Customers	Participating Customers
Green Button Download	1,371,748[39]	N/A[40]
Green Button Connect	1,340,000[41]	56
My Energy Connection	1,371,748	2,657
Xcel Energy Mobile App	1,596,800[42]	443,121[43]
Xcel Energy Web Portal	1,596,800	139,686
Third-Party Applications using Xcel Energy Launchpad	1,340,000	2,249[44]

[39] Number of residential customers active as of December 2, 2024.
[40] The Company is unable to track the number of customers that utilize the Green Button Download functionality.
[41] Approximate number of residential customers with advanced meters installed as of December 2, 2024.
[42] Total retail customers as of December 2, 2024.
[43] This represents total downloads across the Company's eight states. The Company does not track state specific downloads.
[44] Number of customers enrolled in Xcel Energy Launchpad. The Company cannot track the number of customers actively utilizing a third-party application.

DER INTERCONNECTION AND BENEFICIAL ELECTRIFICATION UPGRADE COSTS

Pursuant to SB 24-218, Public Service has implemented tariff updates pursuant to the advice letter filed in Commission Proceeding No. 24AL-0433E to update its Distribution Extension and Interconnection policies limit the costs individual customers need to contribute for certain distribution upgrades. These customer cost caps apply to distribution upgrades necessary to support residential transportation electrification and beneficial electrification, the interconnection of small-scale distributed generation resources (25 kW or less), and for energization and interconnection of DERs to serve residential affordable housing. Public Service is optimistic that these tariff updates will help reduce cost-related barriers to transportation electrification, beneficial electrification, the adoption of DERs, and the development of affordable housing for our customers and communities. The implementation of these tariff updates and the Commission's initiation of Proceeding No. 23M-0464EG also fulfill certain obligations under the 2022-2026 DSP Settlement.[45]

[45] *See* 2022-2026 DSP Settlement, ¶¶ 34-35 (requiring the Company to explore potential solutions to fund transformer and secondary system upgrades required for residential and small commercial solar deployments and for the Company to ask the Commission to conduct a proceeding to investigate related policy, program, and tariff updates).

XI. CLIMATE RESILIENCY

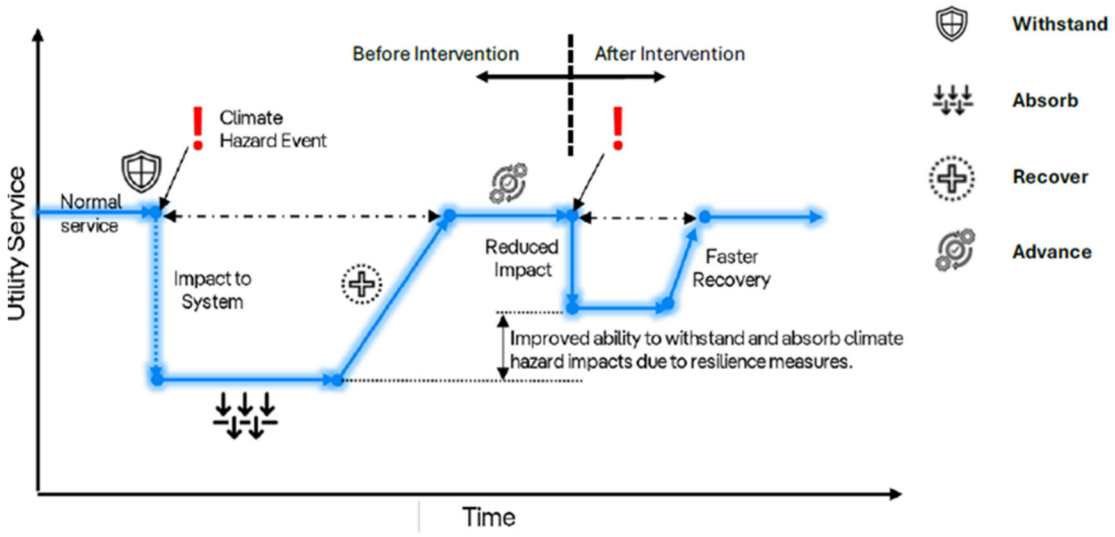
In addition to planning for customer-driven capacity needs, we are modernizing and hardening the grid to enhance the resiliency and reliability of our system. This includes making investments in physical infrastructure as well as tools and software that provide better visibility and situational awareness into the state of the system to better anticipate and respond to climate and weather driven risks. Typically, these outcomes have been effectuated through the design standards the Company implements when deploying new infrastructure, mitigation strategies designed to address specific risks, as well as the way that the Company maintains and replaces assets through the Asset Health & Reliability category. Our current standards address climate impacts by limiting span lengths, building to standards to withstand higher winds and ice loading, and when needed undergrounding overhead conductors.

More broadly, resiliency can be achieved through one or more of the following pathways as depicted by Figure 50 below.

1. Hardening and Strengthening Assets to withstand the adverse impacts of an event
2. Increasing the system's ability to anticipate when a climate hazard may occur and absorb its effects
3. Bolstering the system's ability to respond and recover after an event

.

Figure 50: Utility Resilience Framework



As part of this process, we are also expanding upon the analytical tools that we have available to better inform planning and operational decisions to ensure that as more of our customers' lives depend on the grid, it will continue to be resilient and reliable.

CLIMATE RISK AND RESILIENCY STUDY

The availability of global climate models at lower resolutions (e.g. an area of a few kilometers), is a powerful tool that can be incorporated into utility investment planning framework decisions. These long-term climate models can be downscaled to assess the exposure of assets in defined geographic regions to climate risks. By better understanding exposure to climate variables, utilities can be better prepared to address and mitigate climate-related risk.

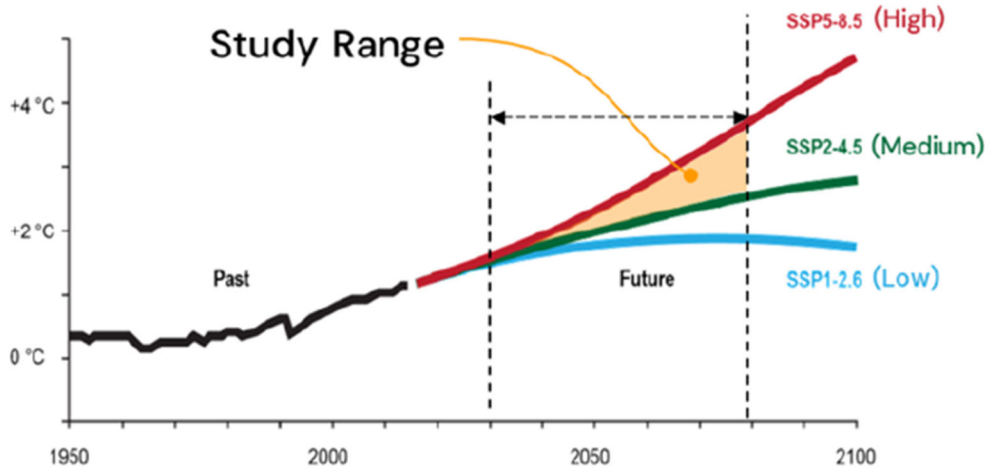
The most recent step the Company has taken in its climate resilience journey was working with ICF to incorporate long-term climate modeling into a Climate Risk and Resiliency Study (the full report is provided as Appendix 6). As part of the Settlement Agreement from the last Distribution System Plan, the Company agreed to hire a third-party consultant to help further its use of data related to climate risks including extreme temperature, extreme winds, wildfires, drought, and floods that could be used to inform cost effective distribution investment decisions. While the study requirement originated from the Settlement Agreement, the work performed by ICF is well aligned with the Company's intentional evolution towards incorporating multiple objectives into planning and operational investment decisions.

Working with ICF, the Company, established a cross-functional "Study Team" comprised of internal subject matter experts ("SMEs"). This included SMEs from the Integrated System Planning (including distribution planning and standards), Distribution Operations, Energy and Demand Forecasting, Wildfire Mitigation, and Enterprise Risk amongst others key groups and SMEs.

Climate Scenarios Modeled

Due to uncertainty associated with future GHG emissions trajectories and the response of Earth's climate systems to these emissions, climate change projections provide a range of plausible climate futures. As a result, the Company requested ICF model two different climate scenarios under the Shared Socioeconomic Pathways ("SSP"s) that were developed in preparation for the Intergovernmental Panel Climate Change's ("IPCC") Sixth Assessment Report. The Study Team chose SSP2-4.5 50th percentile and SSP5-8.5 90th percentile climate scenarios for this analysis as reflected by Figure 51 below. Each pathway corresponds to a different projected risk in global surface temperatures.

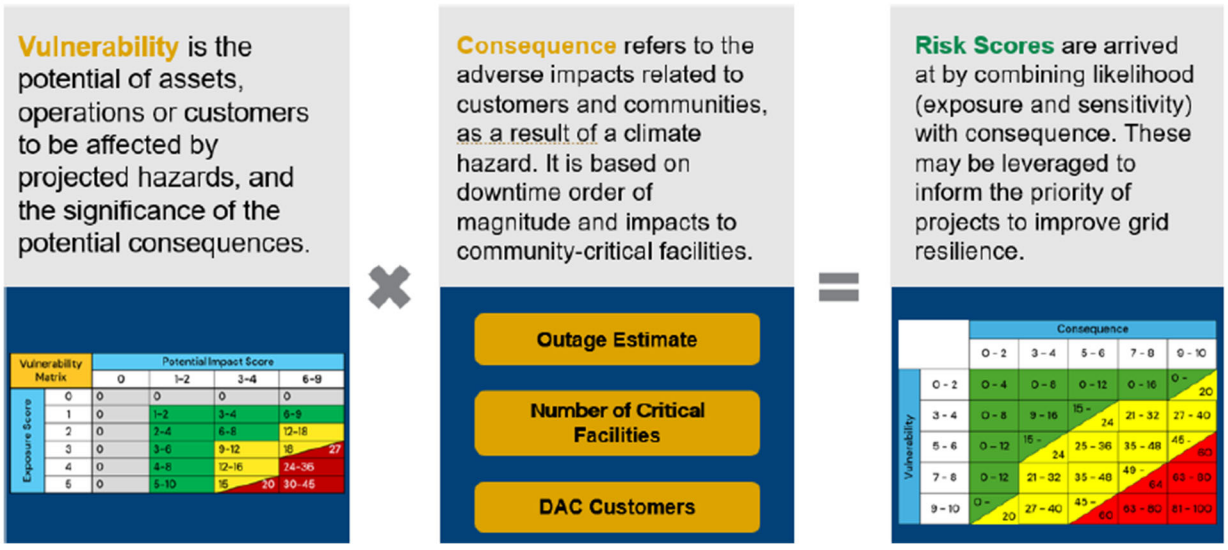
Figure 51: Projected global surface temperatures under three different SSP scenarios.



Climate Exposure and Overall Risk Framework

The global climate modeling under the different SSP pathways was the first step used in the overall study process. The climate projections were used to specifically perform the asset exposure analysis which is the first step in the asset vulnerability assessment. Overall, the analysis in the study assesses the interaction of climate-related vulnerabilities and the consequences of exposures to variables as depicted in Figure 52 below.

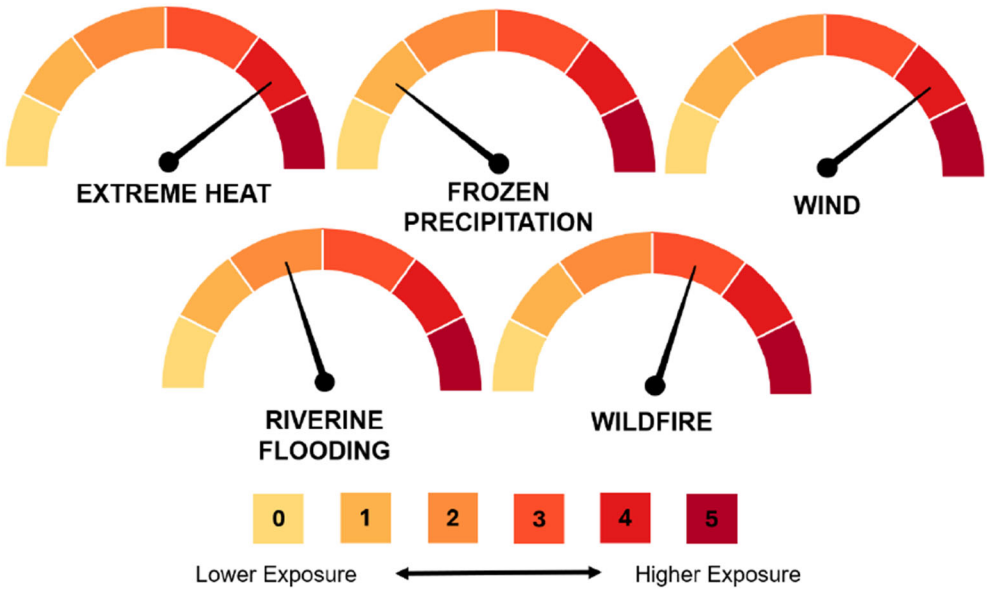
Figure 52: Climate Risk Scoring Framework



The Company worked with ICF to assess the asset exposure of climate hazards across five categories which included Extreme Heat, Frozen Precipitation, Wind, Riverine Flooding, and Wildfire. A summary of overall asset exposure across all categories is

presented in Figure 53 and Figure 54 below. It is important to note that exposure is independent of asset sensitivity – in other words a high degree of exposure does not necessarily mean an asset may be vulnerable to climate risk. This is often the case where assets have been designed based on standards to withstand the exposure or equivalent conditions.

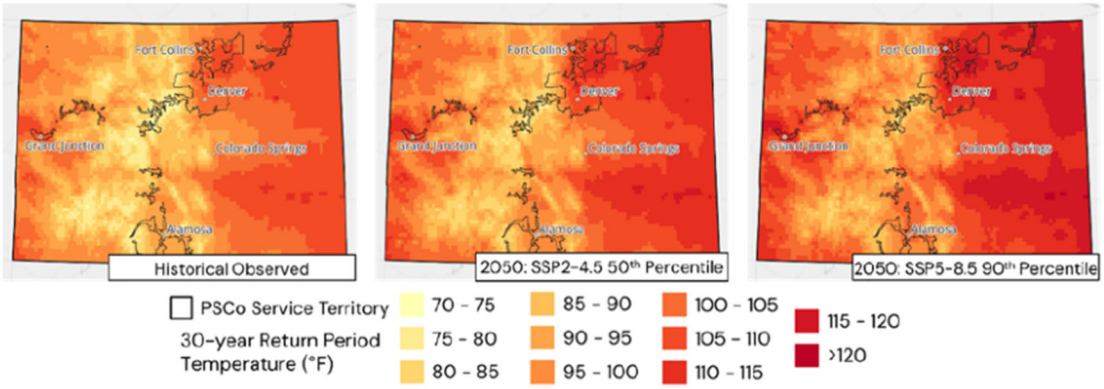
Figure 53: Maximum asset exposure by 2050 (SSP2-4.5 50th percentile) for each climate hazard.



The asset analysis included evaluating exposure and vulnerability of distribution line equipment (e.g. poles and overhead conductor), Substations (e.g. substation transformers and circuit breakers) and Distributed Energy Resources (e.g. Battery Storage and Solar Panels).

Long-term climate change has the potential to have significant impacts on how the Company plans and operates the system. For example, to better evaluate the impact of present day and future exposure to high temperatures, the study modeled projected 30-year daily maximum temperatures, number of days with maximum temperature over 95°F, number of days with maximum temperature over 104°F, number of 2-day heat waves with average temperature over 86°F, and duration of 2-day heat waves with average temperature over 86°F. As indicated by the chart below, the climate models suggest meaningful increases in maximum daily temperatures which can increase weather driven cooling loads amongst other things.

Figure 54: Historically observed and future projections of 30-year daily maximum temperatures across the PSCo service territory.



However, the forecasted temperature increases do not preclude the possibility of extended cold snaps and polar vortex events. Therefore, it will be critical to evaluate our system holistically, particularly as the Company's CHP and the state's policy goals result in gas load being shifted to the electric system and as the system becomes winter/dual peaking.

Vulnerability Assessment

In order to develop asset specific risk scores, climate hazard exposure modeling was combined with the potential impact (the product of sensitivity and criticality of the asset) as indicated by Figure 55 below. Sensitivity is defined as the degree to which the Company's assets could be negatively affected by climate hazard exposures. It captures the extent to which an asset may degrade, fail to perform as designed, or require repair or replacement. Criticality was defined as the extent to which the failure of an asset to operate as designed would result in negative outcomes for the Company's system, customers/the public, or personnel.

Figure 55: Vulnerability Scoring Process Diagram

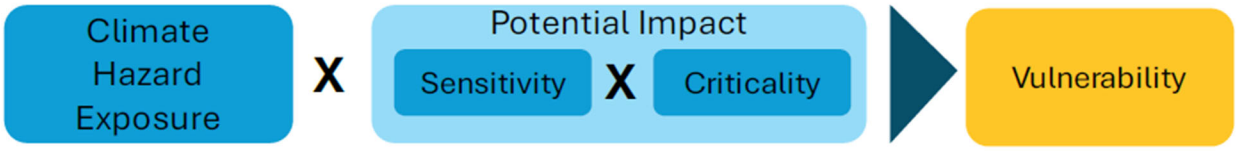
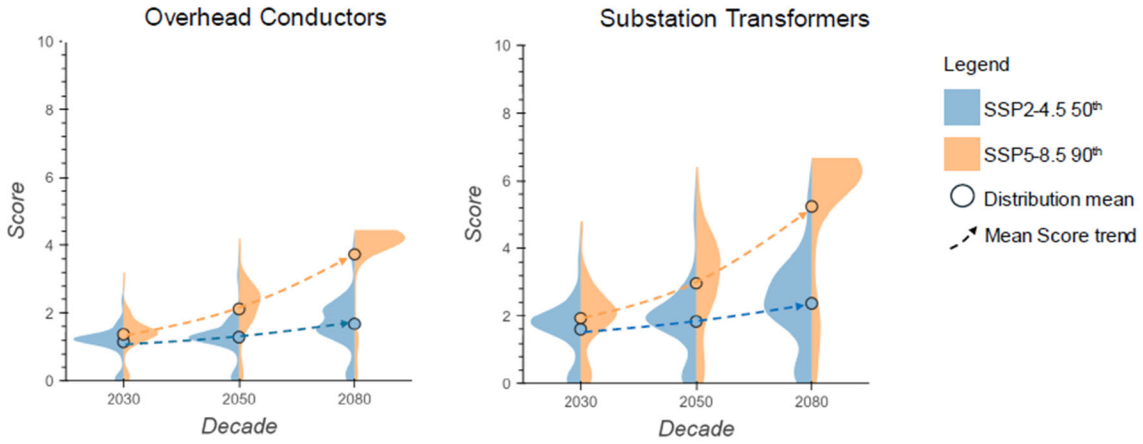


Figure 56 below depicts the vulnerability scores associated with overhead conductors as it pertains to extreme heat. Vulnerability scores were normalized to a 1–10 scale for integration into the risk scoring. A detailed explanation of the risk scoring framework is

provided in the report. By 2050, only substation transformers reach a high vulnerability score, 3% under SSP2-4.5 and 12% by SSP5-8.5

Figure 56: Vulnerability scores distribution for overhead conductors and substation transformers to extreme heat.



Risk Scoring

The final step in the evaluation phase of the study was determining a risk score for asset types. A risk score was generated as a product of vulnerability and consequence. Vulnerability was defined as the potential for assets and operations to be adversely impacted by projected climate hazards, whereas consequence was defined as the significance of the impact on an asset for customers and estimated duration. The consequence score consisted of outage impacts, number of critical facilities connected to each feeder, and customers in disadvantaged communities. Table 24 provides the risk scores related to heat exposure for substation transformers at ten substations (note: full substation names have not been provided for confidentiality reasons).

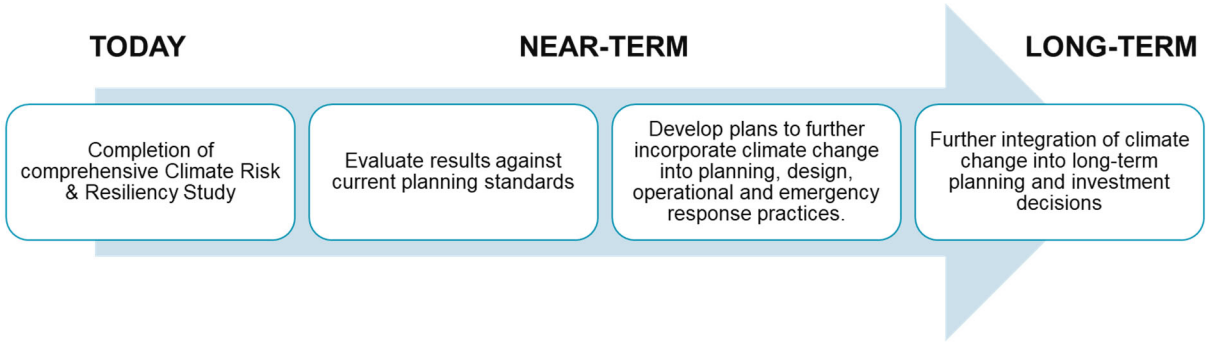
Table 23: Example consequence scores for transformers assets and exposure to extreme heat.

Substation	Outage Estimate Scores		Critical Facilities Scores		Disadvantaged Community Scores		Consequence
	Normalize (out of 10)	Weight (out of 3.33)	Normalize (out of 10)	Weight (out of 3.3)	Normalize (out of 10)	Weight (out of 3.3)	Total Score (out of 10)
G.J.	2.5	0.8	2	0.7	10	3.3	4.8
A.	2.4	0.8	0	0	10	3.3	4.1
S.	2.4	0.8	0	0	10	3.3	4.1
D.	2.3	0.8	0	0	10	3.3	4.1
R.	2.1	0.7	0	0	10	3.3	4.0
G.	2.4	0.8	2	0.7	0	0	1.5
A.	2.4	0.8	2	0.7	0	0	1.5
Av.	2.4	0.8	0	0	0	0	0.8
L.	2.4	0.8	0	0	0	0	0.8
S.	2.1	0.7	0	0	0	0	0.7

Next Steps

Incorporating the impacts of Climate Change into our planning and operational practices is a journey of multiple steps as indicated by Figure 57. While the Company already follows several best practices for planning for resiliency, the results of this study present an opportunity to continue to refine and evolve our thinking. The Company recognizes the importance of leveraging this study in working towards making investment decisions that will meet both the short-term and long-term needs of our customers and system.

Figure 57: Incorporation of Climate Risk into Planning



The final results of the climate study were provided to the Company in October 2024. Therefore, we are still working to comprehensively evaluate the study against our current technical standards as indicated by the second block in the above diagram. As one example of applicability, however, the climate report showed that 19 existing substations are within either the 500-year or 100-year flood plain. We have plans to rebuild four of them, in which case, the flood plain data will be taken into consideration when rebuilding the equipment. However, it is also important to note that the Company worked closely with ICF to incorporate the resiliency impacts of our current design standards in the study process. These efforts are reflected by certain asset types reflecting a lower risk score.

The Company has already integrated FEMA flood plain data as well as wildfire risk zones into its geographic information system (“GIS”) to help inform decision making when it comes to installing new or upgrading existing equipment in the field. The integration of this and other datasets into grid planning will help to ensure a resilient and reliable system.

Incorporating climate resilience into our distribution system planning and into individual distribution project decisions is an important part of being able to meet our Grid of the Future vision, and the climate resiliency study we are presenting in this DSP represents an innovative and proactive first step toward addressing climate-related challenges in the future.

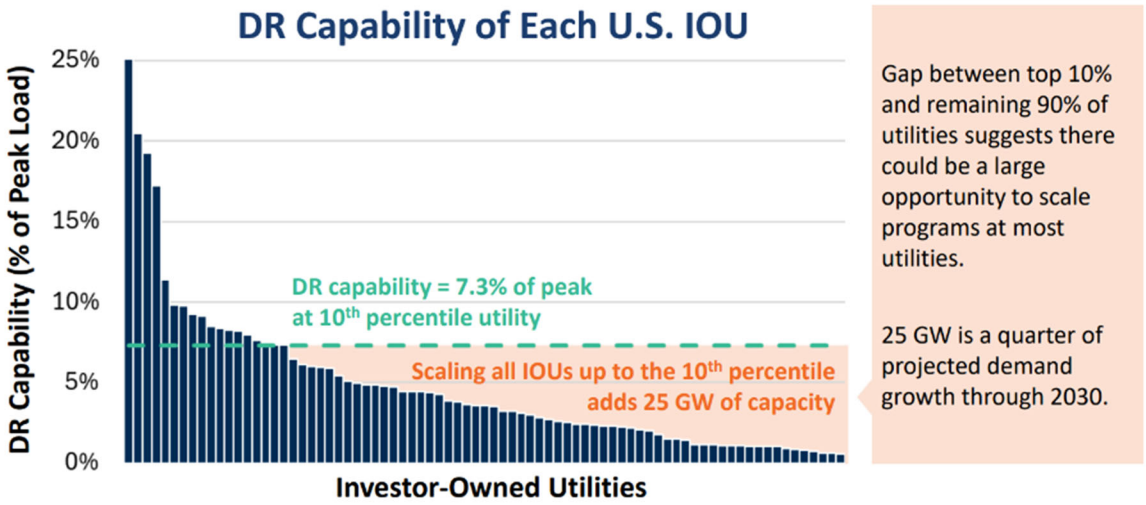
XII. LOAD FLEXIBILITY, OPERATIONAL FLEXIBILITY, AND INFRASTRUCTURE ALTERNATIVES

Given the magnitude of the new expectations for the grid, the Company recognizes the importance of 1) enhancing our modeling capabilities to better reflect the impact of load flexibility; and 2) to the extent that additional infrastructure investments are implicated, exploring a broader and expanded set of non-traditional solutions including non-wires alternatives, targeted demand areas, and virtual power plants amongst other potential solutions. Given that the distribution system is the platform for connecting many of these resources, the Distribution System Plan is an important venue for unifying these concepts. This evolution reflects that our customers, and the corresponding technologies they adopt can have a role in supporting the needs of the grid.

HISTORY/CURRENT STATE

The Company has a long history of employing load flexibility programs to maintain reliability and lower system costs. The largest program, Saver's Switch, was introduced in 2000 and currently has 164,000 participants. These programs have been designed and operated to provide benefits to the bulk electric system by reducing the peak demand impact of weather-driven cooling loads (e.g., air conditioning). In aggregate, the Company's Load Flexibility program today accounts for approximately 550 MW, or 8%, of our coincident system demand. Relative to other investor-owned utilities, this places PSCo in about the top 10th percentile of overall DR capability as indicated by Figure 58. However, the Company is evolving our approach to both modeling and implementing load flexibility solutions to be commensurate with the changing dynamics on the bulk system as well as the distribution system. Regardless of whether the Company is seeking to solve a constraint on the bulk or distribution system, we recognize that resources connected to the distribution system (i.e. DERs) can have a material role as part of the solution set.

Figure 58: Brattle Assessment of Demand Response Across U.S. Utilities[46]



BULK SYSTEM MODELING TO SUPPORT LOAD FLEXIBILITY

Historically, the Company has used an annual planning reserve margin construct because the reliability risk to the system occurred primarily around summer coincident peak loads. Over the last few years, resource adequacy challenges have been experienced at times other than hot summer peaks. To address these challenges, in the last three years, the Company has dispatched flexible load resources in response to eleven non-summer bulk system capacity events as seen in Table 24 below. The need to dispatch load flexibility in non-summer months reflects the evolving resource adequacy requirements of the system.

Table 24: Non-Summer Load Flexibility Call Events

Date	Program	Start Time (Local)	Duration (Hrs)
2/3/2022	PPR, PDP	7:00 AM	4
2/3/2022	EV-CPP, CPP	4:00 PM	4
2/24/2022	PPR,PDP	6:00 AM	4
2/24/2022	EV-CPP, CPP	4:00 PM	4
1/2/2023	PPR	5:00 PM	4
2/23/2023	ISOC	9:13 AM	4
3/7/2023	ISOC	4:06AM	4
1/13/2024	EV-CPP, CPP, PDP	4:00 PM[47]	4

[46] Ramakrishnan, A. Brattle. *Distributed Energy, Utility Scale: 30 Proven Strategies to Scale VPPs.* Presented at ESIG Fall Technical Workshop October 23, 2024.

[47] PDP started at 5:00 PM

1/14/2024	EV-CPP, CPP, PDP	4:00 PM[47]	4
1/15/2024	PDP	6:00 AM	4
10/2/2024	PDP	4:00 PM	4

In 2024, the Company commissioned a Resource Adequacy Study by E3 that was submitted as an attachment in Proceeding No. 24A-0442E.[48] The study recognizes that reliability risk on the bulk system is increasingly occurring in both the winter and summer months due to growth in winter load driven by electrification of heating and lower availabilities of certain generation resources in the winter and summer months (e.g. solar and wind in the respective seasons). Additionally, whereas previously we modeled the impacts of most DERs as load modifying resources (e.g. resources that reduce net load), we now model DERs on the supply side of the Loads & Resources table which allows us to take a probabilistic approach to determine the ability of DERs to meet system conditions. In addition to this revised approach, we are also modeling EV load using aggressive managed charging assumptions that reduce the impact on system peak.

As a result of the changing dynamics of the system, the Company's consideration of load flexibility potential must also evolve. For example, while current residential thermostat programs designed to address cooling loads are well suited to summer peaking systems with moderate winters (i.e. systems that are not likely to be winter peaking), we will see an increasing need in the future for resources that are available and dispatchable throughout the course of the year such as batteries and EVSE equipment. This is because we forecast the bulk system to be winter peaking by 2039 as demonstrated in our recent JTS modeling. Similarly, as Section VI of the Plan demonstrates, we forecast significant adoption of electric space and water heating to drive new local winter peaks on the distribution system. This logic underpins the Company's recent modeling analysis of Virtual Power Plants in the JTS which modeled VPPs as four-hour, behind-the-meter lithium-ion batteries.

DISTRIBUTION SYSTEM MODELING TO SUPPORT LOAD FLEXIBILITY

Distribution System Planning, unlike bulk system planning, is driven by resolving overloads relative to the local peak conditions on a specific piece of equipment or asset – referred to as non-coincident peak. Each asset (e.g. substation transformer banks, feeders, and service transformers) in the hierarchy that makes up the distribution system can have a unique peak that is determined by the loading patterns of the customers that are ultimately connected to those assets. Additionally, unlike the bulk system, which can draw upon a series of escalating actions to ensure real-time resource adequacy (e.g. dispatching peaking units, demand response, load shedding), the mitigations available to

[48] Hearing Exhibit 109, Attachment ZM-1, Proceeding No. 24A-0442E.

relieve overloads on the distribution system in real-time are more limited. As we explore non-traditional solutions, it is important that we do so in parallel to maintaining a 75% utilization rate on the distribution system. That way, if non-traditional solutions fail to deliver the intended results, it will not require us to take more drastic measures such as opening circuit breakers to de-energize customers to avoid overloading and damaging equipment.

The Company's shift to implementation of the LoadSEER modeling and CYME distribution power flow software provides us with additional granularity and capabilities to understand forecasted hourly constraints on the distribution system. The more sophisticated modeling is a critical foundation for ultimately identifying and implementing non-traditional solutions. However, one of the challenges associated with implementing non-traditional solutions is the lack of price discovery and market signals on the distribution system. For example, tools like time-of-use rates have been designed primarily to address bulk system impacts, but these mechanisms are not reflective of local distribution system benefits. Similarly, as the Company argued in the 2022-2025 RES Plan, the lack of locational value provides no incentive to developers to develop resources in areas that could provide grid benefits. In other words, by assuming that each kW and kWh on the distribution system is the same regardless of when and where it is injected, it is inherently creating a disincentive for DERs to provide grid value. Therefore, the Company believes that establishing a locational value methodology is fundamental to developing a more robust ecosystem of both Company proposed and third-party proposed non-traditional solutions. Indeed, other states (California, New York) have already ventured down this path. The Company acknowledges that the Commission was tasked with this requirement as a result of SB 24-207, and we look forward to working with the Commission to inform a locational value methodology that can help unlock additional value on the distribution system from DERs.

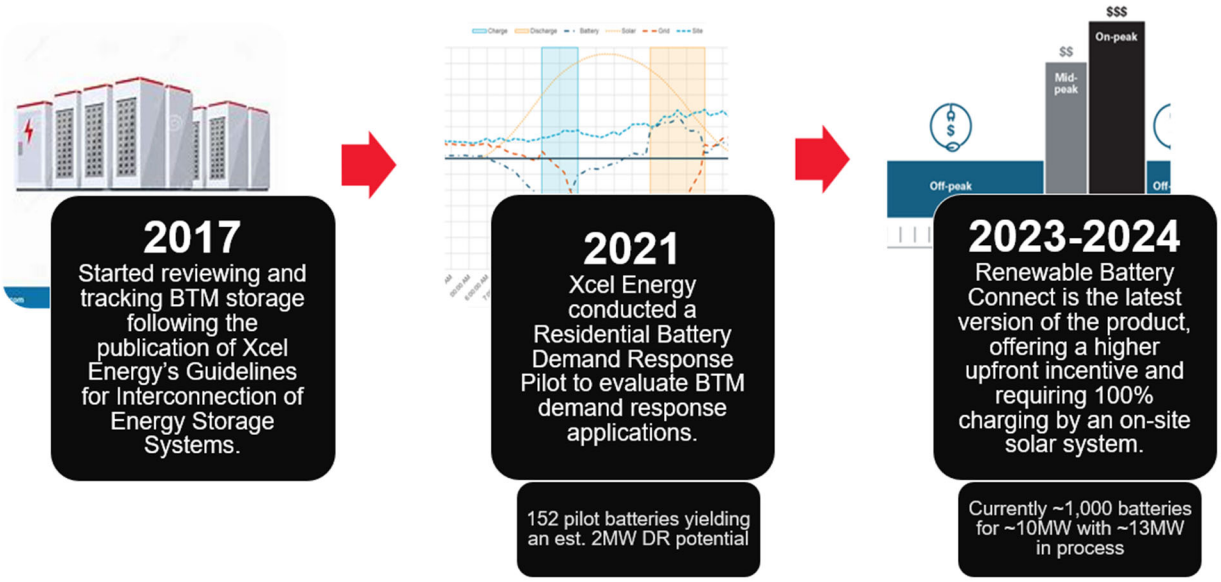
Notwithstanding some of these questions, the Company is pleased to report on the status of several near-term, non-traditional solutions designed to mitigate system needs at both the bulk system and distribution system level.

VIRTUAL POWER PLANTS

Renewable Battery Connect and VPP Tariff

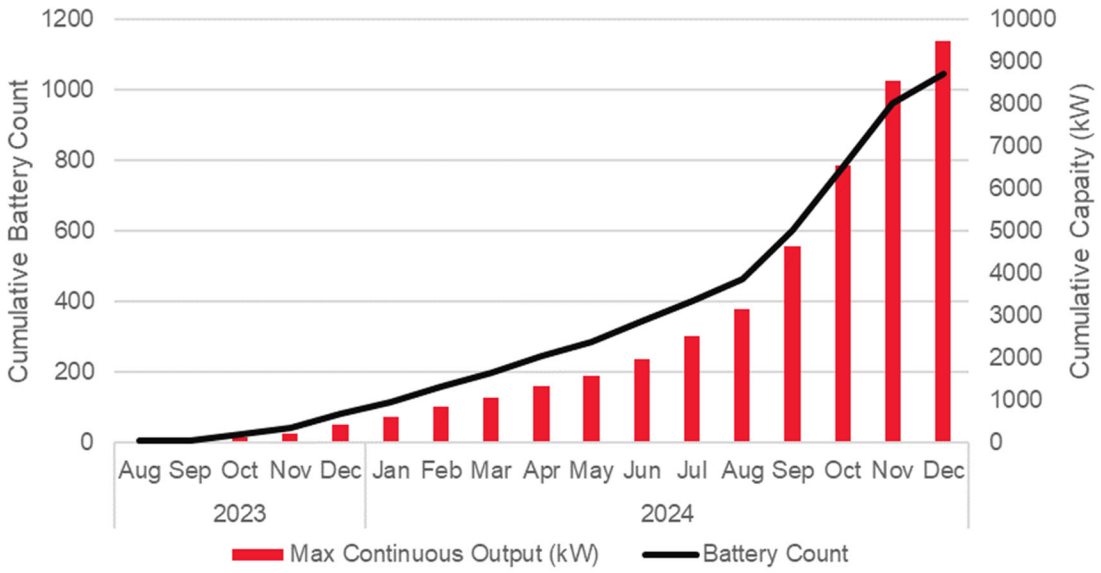
The Company established its Virtual Power Plant program through Renewable Battery Connect in the 2022 – 2025 RES Plan. The program evolved through a series of initiatives that began in 2017 working to further integrate energy storage and the value that it can provide on our system as indicated by Figure 59.

Figure 59: Evolution of Renewable Battery Connect



Customer response to the program has been extremely positive and the Company currently has enrolled approximately 10 MW of behind-the-meter battery capacity with another 13 MW in the interconnection queue as indicated by Figure 60. The Company is not aware of any battery-based VPPs programs in North America that have achieved this scale in such a limited amount of time.

Figure 60: Renewable Battery Connect Capacity and Count



The Company is actively working to add additional battery providers to program eligibility. The Company expects to further expand the use of battery-based VPP programs by developing a performance-based compensation tariff. The Company will provide additional details through its upcoming VPP Tariff filing in February of 2025.

As noted in the Company's last Distribution System Plan, the goal is to unify and coordinate the dispatch of batteries from multiple different providers into a single platform via Aggregator DERMS. We anticipate using Aggregator DERMS to support Renewable Battery Connect as well as the forthcoming VPP tariff program.

The Company has also been working with Resource Innovations to track metrics and KPIs consistent with the Commission's Decision in the last Distribution System Plan pertaining to approval of Aggregator DERMS (formerly referred to as DRMS).

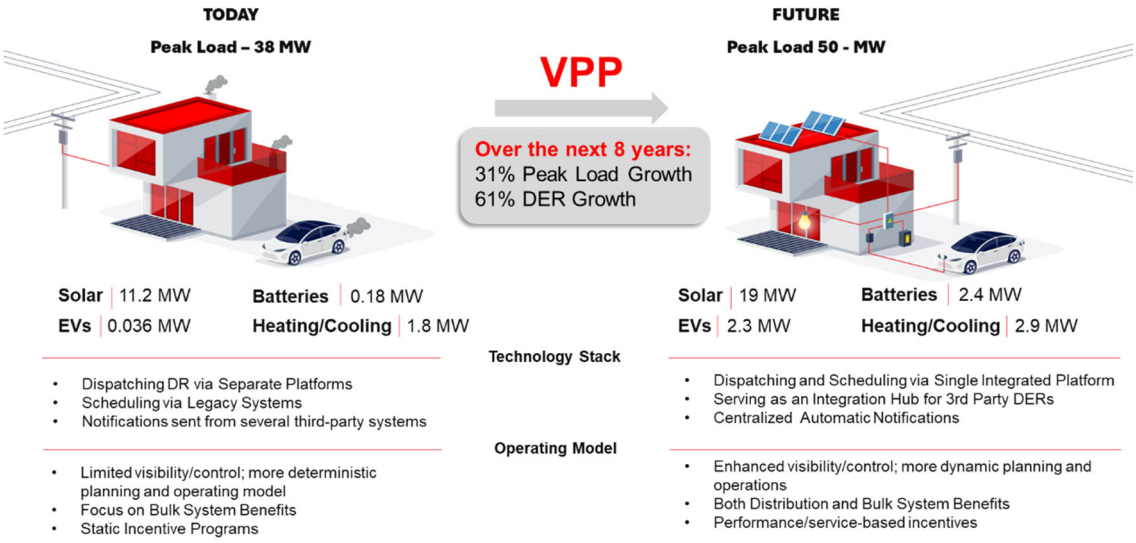
Prime Time VPP

Xcel Energy, the City of Boulder, the University of Colorado Boulder ("CU Boulder") and the National Renewable Energy Laboratory ("NREL") have partnered to enable a clean energy future through the deployment of a VPP. All partners share a clean energy vision, and each has commitments through their Clean Energy Plan or Climate Action Plans. This initiative is known as Prime Time VPP.

The Company was one of three utilities selected by the Department of Energy in 2024 under the Distributed Energy Systems funding opportunity for its joint VPP proposal with Boulder, NREL, and CU Boulder. Prime Time VPP will effectuate several pieces of the Company's longer term DERMS and VPP strategy by introducing more sophisticated and

coordinated control at the distribution level. An overview of the project is provided below as Figure 61.

Figure 61: Prime Time VPP Overview



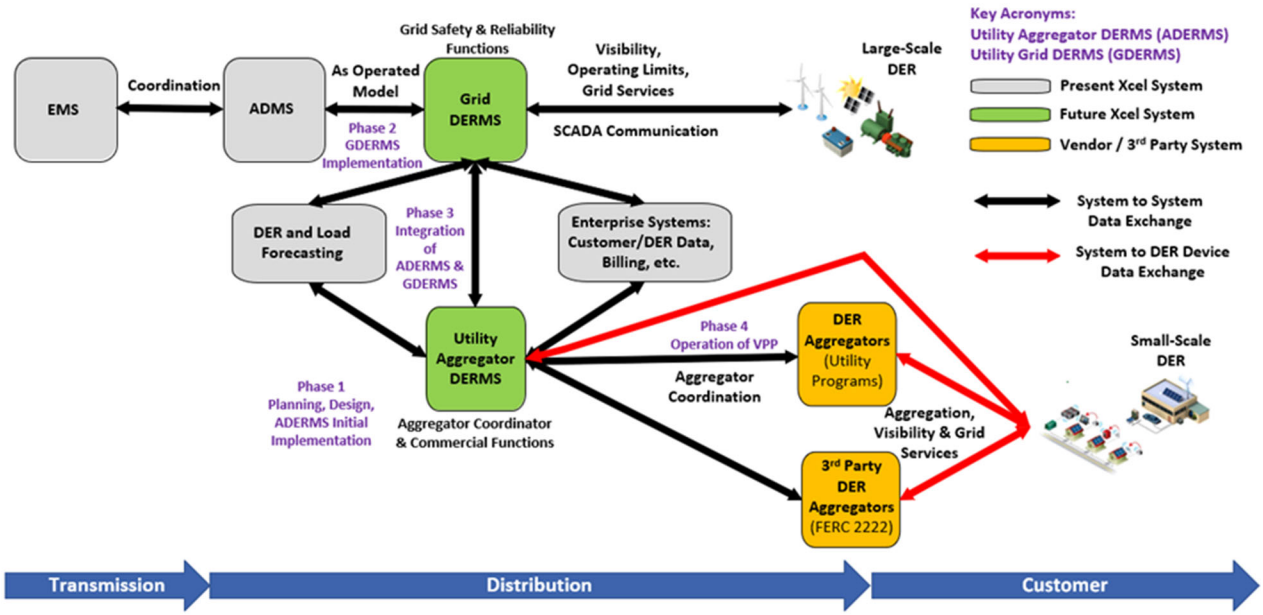
The Company has already integrated an ADMS for distribution system management, established robust DR programs, and is developing a Private LTE network, AMI, and FAN, all serving as core capabilities to enable the proposed VPP. As part of this project, we will build on these functions and capabilities by procuring DERMS technology and integrating with existing IT/OT systems. The integration includes communication networks, interface to end-devices, and measurement and verification ("M&V') to support the implementation of the VPP use cases.

A well-structured and holistic architectural approach for the VPP control and communication is crucial for scaling its technical and commercial functions. This is critical as more devices, use cases, and programs are incorporated in the future. We will implement the VPP technology consistent with the DOE promoted grid architecture principles of the Pacific Northwest National Laboratory ("PNNL") i.e., laminar coordination framework.

At present, distribution operations only has visibility into large-scale DER through existing ADMS. This visibility is accompanied by limited DER control and management capabilities. Furthermore, distribution operations lacks visibility of DR programs, event calls, and aggregated behavior of behind-the-meter customer DER. In the VPP project, we will implement technologies to overcome these limitations. As shown in Figure 62, the Prime Time VPP will add new DERMS components, ADERMS, GDERMS, their

integration with each other and existing enterprise IT/OT systems, as well as the supporting communication and interfaces with third-party platforms and customer devices. The figure also shows the VPP project phases and the value flow between participants.

Figure 62: VPP End-to-End System, Components, Interfaces, Project Phases & and Value Flow



MANAGED CHARGING

The Company is making strides in actively managing EV charging loads and continues to advance its capabilities to leverage these flexible loads for the benefit of all customers. The "Optimize Your Charge" program, which incentivizes off-peak charging during scheduled, pre-determined windows, is currently available through 2026 but is planned to be phased out long term due to the widespread deployment of advanced meters and the adoption of Time-of-Use ("TOU") rates. These TOU rates already encourage off-peak charging through lower pricing, capturing most of the value of passive load shifting to specific, static time periods. As a result, the incremental system value from this passive program is limited. In contrast, the Company's "Charging Perks" program offers greater potential by actively managing charging to support integration of renewable energy and reduce peak demand. Today, Charging Perks addresses these issues at the bulk system level, and in the future we plan to leverage EV charging loads to actively address local distribution constraints as well. Our systems will evolve to provide charging signals at the distribution feeder or service transformer level, supporting higher EV penetration and reducing the need for grid investment.

Distribution System Optimization via Managed Charging

The Company issued an RFP for the next iteration of its EV managed charging solution in Q4 of this year. While the vendor selection and contract negotiation processes are still underway, one of the new capabilities we sought in this platform is the ability to establish an objective function for managed charging schedules that seeks to reduce local grid impacts – effectively enabling the use of managed charging to support specific needs and locations on the distribution system. The goal is to deploy this capability on a more limited basis before further integrating the coordination and dispatch with future enterprise DERMS capabilities.

OTHER DISTRIBUTION LOAD RELIEF OPPORTUNITIES

Targeted Demand Areas

Targeted Demand Areas are localized geographic areas in which future capacity constraints are likely, however specific mitigation projects have not been prioritized and funded in the 5-year distribution capacity capital budget because the anticipated constraints are farther out in the future (e.g. 6-10 years). Enhanced deployment of end-use specific customer interventions to reduce, manage or shift load in these geographic areas is intended to delay or eliminate the need for traditional capacity reinforcements in these areas. Enhanced deployment of customer interventions can include geographically targeted marketing, bonus rebates, and higher touch delivery methods such as direct equipment installation. Below is a comparison framework for how DSM is used to meet distribution system planning needs that the Company presented in our most recent DSM Plan, shown below as Table 25.

Table 25: Evolution of DSM to Meet Distribution System Planning Needs

	Traditional DSM/EE	Targeted Demand Areas	Non-Wires Alternatives
Primary Benefit Stream	Avoided energy/ capacity/commodity	Avoided Distribution Capacity	Project Deferral Value
Internal Lead	Demand-side Management	Demand-side Management	Distribution System Planning
Specificity of Analysis / Benefits	System-wide	More granular than system level, less granular than project specific.	Project specific (i.e. limited to projects in the five-year capital budget).
Cost Threshold	None	None	>$2M
Implementation Timeline	Ongoing	5+ years out	Years 3-5 of current capital budget

The concept is similarly applicable to both the gas and electric systems, though the details of system planning and implications of potential impacts on future infrastructure construction may be different in practice. The Company's methodology to support TDAs for the gas system, including an approach for estimating the value of avoided infrastructure investment, was recently agreed to by settling parties and approved by the Commission in Proceeding No. 23A-0589EG, the Company's 2024-2026 DSM Plan.

Consistent with the Settlement Agreement in the last Distribution System Plan, the Company is proposing to bring forward a targeted demand area pilot to address one or more locations the Company has identified as opportunities. These are areas where future capacity constraints are likely in the 5+ years out timeframe, and specific mitigation projects to address these constraints are not in the current 5-year budget plan. Several of these areas have relatively small overloads, which the Company hypothesizes can be solved with targeted demand-side management and/or DER deployment. A summary of the identified areas is provided as Table 26.

Table 26: Potential Targeted Demand Areas from the Grid Needs Assessment

Device ID	Device Type	Division	First Year of Risk	MVA at Risk (MW)	Annual Hours at Risk
ADOB_TR1	Bank	Western	2033	0.1	1
IDAH2944F	Feeder	Front Range	2033	0.2	1
ALLI_TR2	Bank	SW Metro	2031	0.7	4
FRUI_TR1	Bank	Western	2031	0.2	1
GJCT1104W	Feeder	Western	2030	0.1	3

The potential projects for the targeted demand areas pilot represent a diverse mix of residential customers and commercial customers and therefore has the potential to provide the Company with experience across various customer demographics. Additionally, the loading on these assets reflects a mix of summer and winter peaking non-coincident loads.

Table 27: Customer Counts in Potential Targeted Demand Areas

Device ID	Device Type	Residential	Commercial	DI Community
ADOB_TR1	Bank	1869	464	No
IDAH2944F	Feeder	1755	667	Yes
ALLI_TR2	Bank	8497	1204	Yes
FRUI_TR1	Bank	1420	91	Yes

GJCT1104W	Feeder	583	386	Yes

The Company is planning to leverage existing approved budget through its 2024-2026 DSM Plan to support this pilot and is therefore not seeking Commission approval of any funding associated with TDAs in this plan. As a general principle, the Company will plan to leverage any existing DSM programs and DERs to help address TDA constraints. To the extent that existing resources and incentive levels cannot address those constraints, the Company will evaluate using enhanced rebate levels and/or other enhancements to program delivery and customer engagement to support the TDAs addressed through this pilot. The Company will use its learnings from this pilot to inform the need for any new programs or program modifications needed to support the load relief sought for future TDAs. The Company will provide updates on this pilot through future DSM status reports.

Non-Wires Alternatives

Non-Wires Alternatives ("NWA"s) are intended to delay or avoid the need for a specific capital project or relieve excess demand in an area with capital projects that have been identified and budgeted for and that meet certain criteria. Please see the Non-Wires Alternatives Suitability screening section for additional detail.

OPERATIONAL FLEXIBILITY

In addition to the longer horizon needs identified and potentially mitigated through NWAs and TDAs, the Company has identified situations where load growth has outpaced the in-service dates for infrastructure projects. As a result, we have developed several short-term projects that allow us to mitigate additional grid needs until completion of the capital projects. We anticipate these types of solutions being increasingly part of the toolkit based upon forecasted load in Colorado driven by various factors, including policy-related (e.g. DER adoption) and economic development (e.g. greenfield development, infill housing, and industrial growth).

Mobile Storage for Temporary Capacity Needs

The Company is pursuing an opportunity to leverage a mobile battery energy storage system ("MBESS") to bridge a short-term capacity shortfall in Denver. The Denver Terminal Substation is forecasting two substation bank overloads in 2026. Denver Terminal banks #4 and #5 (DTER_TR4 and DTER_TR5) are forecasted to overload in 2026, with a 1.3 MW and a 1.7 MW N-0 overload, respectively. The Company has initiated a capacity project to install Denver Terminal bank #8, however, due to supply chain lead times exceeding three years, the project cannot be completed until Q4 2026, after the summer peak.

Figure 63: Example of Mobile Battery Trailer



This capacity shortfall is prohibiting new growth for low-income housing from receiving electric service until the capacity upgrades are in place. As a solution, the Company is installing a 1 MW/2 MWh MBESS on an owned parcel of land along West Colfax Avenue that used to site the Company's retired 4kV Java Substation that has since been decommissioned (an illustrative example is provided above as Figure 63). The system will interconnect to the local distribution system and will be available for system operators to shave peak demand. Once the substation transformer project is in-service, the MBESS can be relocated to another location on the grid to relieve capacity constraints.

The pilot of the engineering, operations, and maintenance of a mobile battery energy storage system will enable to the Company to evaluate its value to mitigate future demands from electrification.

Short-term Load Relief at Sandown Substation

An example of the use case for Operational Flexibility is the series of projects in process to relieve existing capacity constraints on the SAND1747 and SAND1131 Feeders. There are two projects in the works in this area. The first is the construction of a new SAND1748 feeder. The second is the construction of new Stapleton substation. As designed, the new SAND1748 feeder (which is scheduled to be in service in 2026) will take load currently served by the two overloaded existing feeders, SAND1747 and SAND 1131 thereby eliminating the overload condition for these two feeders. The new SAND1748 feeder will be overloaded upon initial construction until some of the load is shifted to a feeder from the new Stapleton substation. The Stapleton substation is not scheduled to be in service until late in the action period of this Plan, at which time the capacity overload on SAND1748 will be mitigated. Thus, a temporary solution is needed to mitigate the capacity risks currently on SAND1747, SAND 1131 and the future capacity need on SAND 1748.

Short-term Load Relief at Tower Substation

Another example of the use case for Operational Flexibility is the series of projects in process to relieve existing capacity constraints at Tower substation. Our Tower Substation is facing a substantial capacity shortage that will not be alleviated until 2026 when a new third transformer is to be installed. For the next two years, customer engagement in demand management programs can serve a critical need to reduce capacity constraints. Xcel Energy has targeted 50 MW of enrolled demand management load through our Saver's Switch, AC Rewards, Renewable Battery Connect and Peak Partner Rewards programs to alleviate shortages. The Company intends to dispatch enrolled demand response customers in the area as needed in accordance with program rules to mitigate this localized risk until the new transformer is in service, at which time, dispatch of demand response resources in this area will return to the general population.

Through a dedicated marketing campaign, our Marketing team is reaching out directly to Tower Substation customers. We are highlighting the benefits and savings of participating in energy management and how our Demand Management programs align with their sustainability goals.

Our Account Managers are using custom email templates and engagement packages to connect with managed accounts in the relevant area. Additionally, our Commercial & Industrial ("C&I") Program Delivery team has hosted a Colorado "Summit Webinar" to explain how our Demand Management programs work and how to enroll. Finally, we have partnered with Michaels Energy to provide in-person outreach and engineering services, driving C&I customer enrollment in our Demand Management programs.

Future of Load Flexibility

Incorporating load flexibility into our long-term planning process is foundational to facilitate progress toward and achievement of the state's and our customers' ambitious energy policy goals while keeping bills as low as possible. To effectuate achievement of this goal, we have begun integrating similar constructs into our long-term system modeling. Through the modeling the Company conducted with Kevala, we intentionally created a framework to examine the potential benefits of load flexibility. The load flexibility sensitivities we modeled represent an avoided long-run cost of between $3-5 billion in capacity investments by 2050. The Kevala modeling represents just one subset of how DERs may be able to support the grid in the future. However, this work is conceptual for now and our near-term focus is on procuring the foundational tools and technologies, establishing new processes, and creating the valuation methodologies that will position the Company to achieve these this critical objective. There is much more work to be done to begin to realize these types of benefits, and we look forward to working with the Commission and stakeholders to enable these outcomes in future proceedings.

To that end, the Company has started planning a comprehensive load flexibility study to better understand technologies, customer adoption potential and program models that the Company can support in the future to realize the benefits associated with load flexibility. This study will include an assessment of technology and program models that have recently emerged and are developing. The Company expects that the scope of work for this study will include development and execution of an intentional plan for collecting feedback from industry experts and Colorado stakeholders in 2025. This plan will be focused on establishing a shared understanding of suitable timelines for technology adoption and to confirm major research objectives prior to collecting additional data from customers. The results of this study will inform the Company's next Strategic Issues and DSM Plan filings in 2026.

XIII. GRID MODERNIZATION AND GRID INNOVATION

This Section of the plan discusses the Company's comprehensive grid modernization as well as requirements of Commission Rule 3533 (entitled "Grid Innovation").

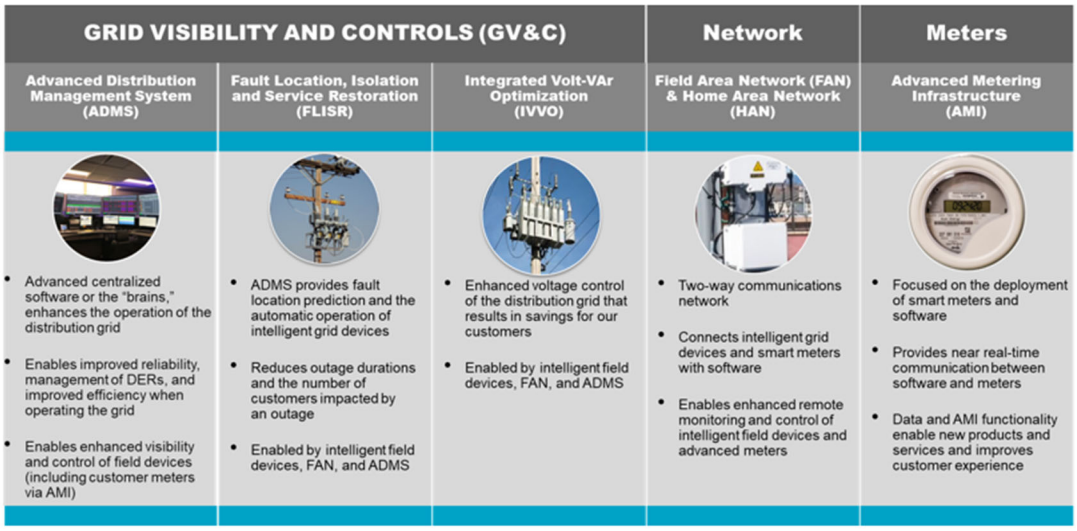
For more than 100 years, Xcel Energy has provided its customers and communities with outstanding service – delivering safe, reliable, and affordable energy. We are looking to the future and advancing the grid to ensure it will continue to provide our customers benefits for many years to come. We are planning and investing in technologies to meet customer and operational needs now and in the future. This means taking a measured and thoughtful approach to maximize customer value, ensuring the fundamentals of our distribution business remain sound, and maintaining the flexibility needed as technology and our customers' expectations continue to evolve.

Commission Rule 3533 provides in part that the utility must address "DSP pilots and programs that are either in progress, planned, or have been suggested by other parties and found to have merit by the utility." The discussion below addresses relevant pilots and programs with detail about each one.

ADVANCED GRID INTELLIGENCE AND SECURITY

Our Advanced Grid Intelligence and Security ("AGIS") initiative is a distinct, long-term strategic plan to transform our electric distribution system to update foundational system technologies and capabilities. The AGIS initiative consists of multiple elements, as shown in Figure 64, that work together to create a more modern and advanced distribution grid intended to meet changing customer demands, enhance transparency into the distribution grid and to system data, and to promote efficiency and reliability.

Figure 64: Advanced Grid Initiatives



ADVANCED METERING INFRASTRUCTURE ("AMI")

AMI is the Company's metering solution, consisting of an integrated system of advanced meters, communication networks, and software that enables the AMI functionality and secure two-way communication between the Company's data systems and customer meters. The AMI meters we are currently deploying, the Itron Riva 4.2, include Distributed Intelligence ("DI") capabilities. This is a powerful distributed processing capability which, when integrated into the Company's broader ecosystem of customer and grid management systems, will unlock both customer and grid-facing benefits. The Company provides regular updates to the Commission on the status of AMI deployment through Proceeding No. 16A-0588E.

AMI is a key element of the grid modernization initiative because it provides a central source of information that interacts with many of the other components of a modern grid. For instance, the capabilities and data delivered by AMI enhance reliability and enable remote functionalities, providing customers with better options for rates, programs, and services. AMI also enhances utility planning and operational capabilities. Access to timely, accurate, and consistent AMI data will provide insights for customers to make informed decisions about their energy sources and usage of reliable and sustainable energy.

The Company has developed a variety of tools and capabilities that leverage AMI. Below,

we provide more details on the types of tools currently available. We plan to continue building and expanding our portfolio of tools.

AMI Energy Usage Dashboard in My Energy Portal. Within My Energy Portal linked to My Account, customers can view their 15-minute interval, hourly, daily, monthly, and yearly usage data. For Colorado customers on TOU rates, the data is broken out by TOU peak periods (off-peak, mid-peak, and on-peak). Customers can toggle between kilowatt-hour usage and cost for each view. Using this presentment tool enhances the customer experience by helping customers better understand their usage patterns.

My Energy Connection. My Energy Connection is a mobile application that provides customers with detailed information on their energy usage. It uses the DI-enabled Home Area Network ("HAN") to display real-time energy usage, while in their home, enabling customers better take control of their usage while providing insights to energy savings and to more Xcel Energy programs that can help them accomplish their energy goals. If customers are away from their homes, data in the app is updated every 15 minutes. Future enhancements will focus on providing customers with appliance-specific usage and cost breakdowns. Having detailed usage and cost by appliance will allow customers to understand where and when they are using the most energy and will provide focus for their energy savings goals.

On Demand Meter Reads. The On Demand Read functionality in My Account provides customers the ability to see their 15-minute interval kilowatt-hour usage for the last eight hours. The On Demand Read functionality provides customers options to experiment with turning appliances and other equipment on and off to identify their energy usage patterns.

Green Button Connect My Data. Green Button Connect ("GBC") is an ongoing electronic data transfer service that allows customers to share their utility data to authorized service providers. These service providers can help customers make smarter choices about their energy usage by providing tools and applications to help them find ways to save energy. Customers can sign up for GBC in the Xcel Energy My Energy Portal and select which service providers to send their data to and how long to share their data with them. GBC sends the premises' billing and usage data down to 15-minute intervals for customers with AMI meters; we note that Green Button is available to all residential customers regardless of meter type, but 15-minute interval data is only available for customers with AMI.

Green Button Download My Data. Green Button Download is a one-time secure data download of a customer's energy usage to their computer. Customers can access Download My Data through the My Energy Portal and download their

usage for personal records or in Green Button format to share with an energy services vendor. Customers with advanced meters can download 15-minute interval data; Green Button is available to all residential customers regardless of meter type, but 15-minute interval data is only available for customers with AMI.

Xcel Energy Launchpad. Xcel Energy Launchpad allows customers to connect applications or devices developed by third parties to the AMI meters through the customer's home Wi-Fi network over the DI-enabled HAN. This permits the customer and third party to directly gather 1-second energy consumption information from the meter. Customers can enroll in Xcel Energy Launchpad through their My Account. The Xcel Energy Launchpad includes a web application that walks the customer through the connection process. As part of the application process, customers are asked to provide consent to connect the meter to their Wi-Fi network. Customers must also provide consent to connect third party devices to the meter via their Wi-Fi network and the HAN.

Bring Your Own Device and Software Development Kit. Bring Your Own Device ("BYOD") and gateway Software Development Kits ("SDK"s) allows third parties to develop hardware and software products that connect to the customer's smart meter via the HAN. Devices can be energy related (thermostats, smart appliances) or non-energy related (security systems, mobile devices). The uses vary depending upon the devices and the functionality enabled.

More Timely Outage Communications. Prior to AMI deployment, customers would receive an initial outage communication in approximately 8 to 44 minutes. AMI meters reduce the time for an initial outage communication for customers with AMI meters to approximately 4 to 26 minutes. As AMI deployment continues, we expect this reduction in notification time to expand to all customers, enhancing the customer experience.

Energy Action Days. Energy Action Days uses digital communications and behavioral science messaging to encourage residential customers to reduce energy consumption during peak events. Participation is voluntary and there are no incentives or penalties for participation or non-participation. Customers with AMI meters receive a follow up email within a couple days of peak events, showing customers how they performed and comparing their performance to their neighbors. This feature is only available to customers with AMI meters.

High Impedance Detection. This grid-facing DI-enabled capability will allow the meters to detect deteriorating or loose connections. Without those capabilities,

such issues on the secondary system, which carries power from transformers to meters, might only be detected if a customer notices a problem, such as flickering lights, or when they cause outages. By proactively identifying high impedance situations, the Company can promptly dispatch crews to proactively address the issue. A significant benefit of this capability is the prevention of outages, which enhances service quality for our customers and reduces the Company's outage response costs.

Location Awareness. This grid-facing DI application can improve accuracy in outage management and notification and improve accuracy in planning and operational modeling.

Remote Connect/Disconnect. The Riva 4.2 meter's internal service switch can be used to remotely connect or disconnect power to a residential or small commercial customer's electric service using a command transmitted from the AMI head-end application. This capability is now available and in use.

Grid Visibility Tool ("GVT"). GVT is a tool the Company built that uses AMI interval and event data with GIS asset information to help visualize grid information such as power quality information, transformer and feeder loading. GVT is a transformational tool that provides the Company visibility to energy usage, power flow, power quality, and meter events at customer meters and distribution transformers that previously was not possible. This will enable more proactive planning and operations on this portion of the distribution system that include identification of overloaded transformers and power quality issues that will support more proactive and improved service quality for customers.

Power Quality. AMI provides power measurement and voltage data at each meter within the distribution grid, which will be used for power quality identification and investigations. This will help ensure voltage is within acceptable limits from the substation all the way to the customer's point of service. In other words, better monitoring of power quality reduces the potential for out-of-range voltages that may interfere with electronic devices in customers' homes or businesses and helps us identify and more efficiently respond to issues. This AMI data is brought into the Grid Visibility Tool.

Outage Notifications to Company Systems. The Riva 4.2 Meter can use its "last gasp" capabilities to send out a message to our system providing notice of an outage. It also provides notice of power restorations and can be "pinged" to check on the status of service at a location. Taken together, these capabilities, which are

integrated with our Network ("Outage") Management System, provide the Company with quicker and more accurate information regarding outages. We can then use that information to more efficiently and quickly respond to outages, with the result that the Company will spend less responding to outages. If we know very quickly the exact homes and businesses that lost power, it is much easier to promptly dispatch crews to the appropriate locations.

Theft Detection. AMI has built-in theft detection capabilities; while meter theft/bypasses are infrequent, when they do occur, they create dangers to the public and property. This capability of the new meters allows the Company to systematically become aware of these circumstances, reducing costs. Analytics capabilities for theft use cases were complete in 2022.

Meter Diagnostics. AMI meters can perform and transmit meter diagnostics transmit data pertaining to the functioning of the meter and communications module.

EV Detection. DI capabilities can provide the Company with insights into where EVs are located and charging patterns of customers. This information can be leveraged to support system planning, load balancing, and infrastructure upgrade efforts based on awareness of EVs being added to a customer's load profile. This grid-facing use case will also enable the Company to become aware and proactively respond to possible service quality issues and encourage customers to participate in managed charging programs.

Momentary Outages. Using AMI event data, momentary outages can be more readily identified, which can help the Company identify potential issues before they cause sustained outages or affect power quality. Capturing these momentary outages will improve the accuracy of our Momentary Average Interruption Frequency Index ("MAIFI") reporting.

ADMS Bellwether. A select number of AMI meters are selected as "bellwether" meters and support ADMS load flow calculations that support the operation of IVVO and more general power quality.

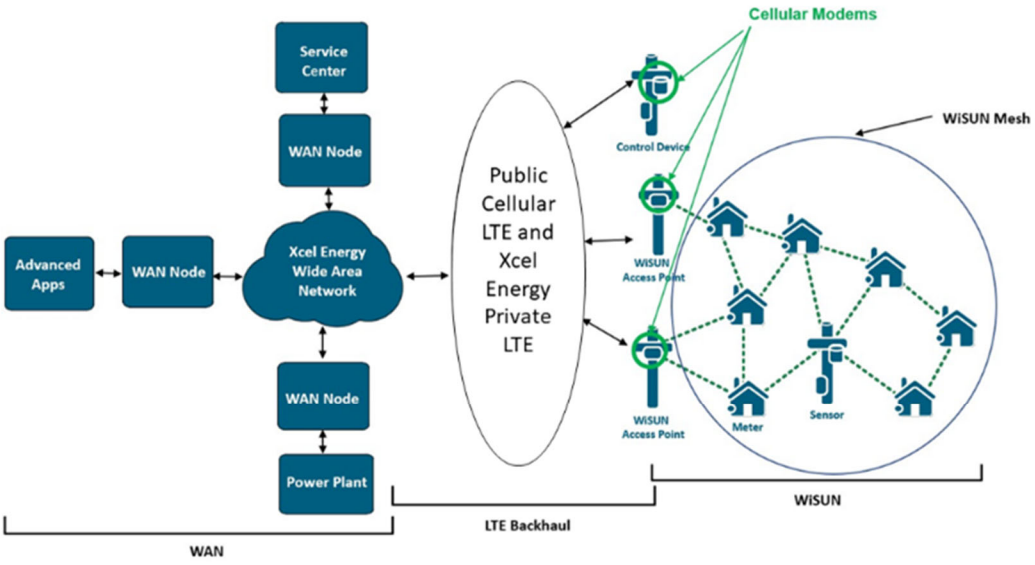
FIELD AREA NETWORK

The Field Area Network ("FAN") is a secure, flexible two-way communication network that provides wireless communications to and from meters, field devices and our information systems.

The FAN connects to the Company's pre-existing Wide Area Network ("WAN"), which is a communications network primarily composed of private optical ground wire fiber and a collection of routers, switches, and private microwave communications. The private fiber and microwave technologies are supplemented by leased circuits from a variety of carriers, as well as satellite backup facilities. The WAN provides high-speed, secure, and reliable two-way communications capability between our core data centers, office locations, service centers, generating stations, and substations. The WAN also provides primary and backup communication capabilities to key facilities in the Company's areas of operation.

The FAN consists of two separate wireless technologies. The first is a lower-speed, private mesh network. The second is a high-speed network backhaul to connect the mesh network to the WAN. The relationship between the mesh, backhaul and WAN are illustrated in Figure 65 below.

Figure 65: Field Area Network Illustration



WiSUN Mesh

Wireless Smart Utility Network ("WiSUN") is a wireless communication standard designed specifically to facilitate communication between smart grid devices. The WiSUN mesh network consists of three main device types: access points; repeaters; and endpoint devices. An access point is a device that will link the Company's endpoint devices with the rest of our communications network. Repeaters are range extenders and are used to

fill in coverage gaps where devices would be otherwise unable to communicate. These two device types are principally located on distribution poles and other similar structures. Endpoint devices include AMI meters and can include automated field devices, such as field devices that installed as part of the FLISR project. The AMI meters are located on customer premises; the field devices are co-located with either pole-mounted or pad-mounted distribution devices.

In addition to being able to communicate with the WiSUN network infrastructure, the AMI meters are able to communicate with each other, becoming a part of a network mesh. This improves range of mesh coverage and adds redundant communication paths between the AMI meters and the WiSUN access points and repeaters.

Backhaul and Private LTE

The backhaul connects the WiSUN mesh networks to the corporate WAN. The backhaul generally consists of public or private Long-Term Evolution ("LTE") cellular service, supplemented by alternatives such as microwave or fiber where LTE service may not be available. LTE cellular modems are installed on poles and are connected to the WiSUN infrastructure. Whether public or private LTE, these modems provide the backhaul connectivity from the WiSUN network to the Company's data centers.

In addition to public LTE service provided by national cellular providers, the Company is currently deploying a private LTE network for the backhaul. The Company's private LTE network will be deployed initially in 27 counties within our operating regions in Minnesota, Colorado, Wisconsin, and Texas. We will add cellular towers primarily at Company-owned and maintained locations, with the private LTE cellular headend located at the Company's data centers in Minnesota and Colorado in a redundant state. Our private LTE will backhaul the WiSUN network, similarly to Verizon, but on a cellular network that is maintained end-to-end by the Company, which increases the reliability and resiliency of the communication network. The current LTE cellular modems support dual SIM cards. As the Company's private LTE SIM cards are added, there will be a secondary, backup option for cellular communications, increasing system resilience.

ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

The Advanced Distribution Management System ("ADMS") is the foundational software platform for operational hardware and software applications used to operate the current and future distribution grid. ADMS is foundational because it provides situational awareness and more automated capabilities that sustain and improve the performance of an increasingly complex grid. Specifically, ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated electrical model and maintaining advanced applications, which provide the Company with greater visibility and control of an electric distribution grid that is capable of more automated operations. In particular, ADMS incorporates Distribution Supervisory Control and Data Acquisition ("D-SCADA") measurements and advanced application functions with an enhanced system model to provide load flow calculations everywhere on the grid, accurately adjusting the calculations with changes in grid topology and insights from devices and sensors. This allows the Company to improve the monitoring and control of power from substations to the customer meter, which enables multiple performance objectives to be realized over the entire grid.

INTEGRATED VOLT-VAR OPTIMIZATION

Integrated Volt-Var Optimization ("IVVO") is an integrated technology that consists of an advanced application in ADMS, two--way communication, and automated field and substation (load tap changers, capacitors, static var compensators). The objective of IVVO is to optimize the operation of the distribution voltage regulating devices and VAr control devices through ADMS. Enhanced voltage control will help achieve the following benefits to the operation of the distribution system and our customers:

- Reduction of distribution electric losses
- Reduction of demand (MW)
- Reduction of energy consumption (MWh)
- Increased ability to host DER

IVVO Status and Reporting

During 2023, the Company continued to install voltage control devices and enable IVVO on additional feeders in accordance with its plans. Table 14 below lists the actual installations in 2023. The Company has been working towards closing out the project in 2024 and expects to do so other than a few load tap changers (“”s) that could not be completed in 2024 are planned for 2025. Any additional savings will be reported in Proceeding No. 16A-0588E.

Table 28: 2023 IVVO Benefits

Benefit	Value
Energy Savings (MWh)	249,817
Demand Reduction (MW)	51.2
Line Loss Reduction (MWh)	8,250

Table 29: 2023 IVVO Infrastructure Installations

Installed Equipment	Previous Years	2022 Actuals	2023 Actuals
Primary Capacitors	620	190	51
SVCs	2,967	283	150
LTCs (some multiple per substation)	68	27	16

FAULT LOCATION ISOLATION AND SERVICE RESTORATION

Fault Location Isolation and Service Restoration ("FLISR") is an integrated technology that consists of an advanced application in ADMS, two--way communication, and automated field and substation (reclosers, switches, substation relays) equipment. FLISR improves customers' reliability experience, reducing the duration of outages and number of customers affected by them. FLISR takes the form of distribution automation and involves the deployment of automated switching devices that work with ADMS to detect issues on our system, isolate them, and automatically restore power.

The deployment of FLISR includes the deployment of automated field devices, upgrades and changes to substation relays, integration with ADMS, and finally, the use of FLISR by our Distribution Control Center. As devices are installed, we go through a process to commission or integrate the devices with ADMS, which includes enabling the two-way communication to the device and a process to add the device and communication settings to ADMS prior to final commissioning in ADMS. Once a feeder has all its devices available in ADMS, we undergo a final testing to release the use of FLISR to the DCC.

We have deployed over 500 automated field devices and plan to continue our deployment through 2025. In addition, as described in the WMP we plan to deploy approximately 900 reclosers as part of the WMP in Proceeding No. 24A-0296E. The reclosers installed as part of the WMP similarly will have two-way communications and be commissioned into ADMS. During non-high-risk days, the reclosers will be programmed with normal operating settings and can be remotely operated from ADMS to utilize the FLISR operating technology both providing reliability benefits during non-high-risk days. This will expand the footprint of the FLISR operating technology to additional distribution feeders in addition to helping mitigate the risk of wildfires.

DISTRIBUTED INTELLIGENCE

Distributed Intelligence (DI) is the localized computing, analysis, and data processing capabilities embedded in the advanced meters the Company is deploying to customers. This includes any backend computing/services needed to support the reliable, secure, and effective processing on the meter. At a high level, the DI platform allows the Company to install software applications on the meter, which can be used to distribute analytics, decisions, and actions away from a central control point to the edge of the grid. By distributing this computing capacity to the individual meter level, DI reduces the strain on the FAN and allows meters to communicate with one another to notify, resolve, and avoid issues that could threaten reliability rather than awaiting instructions from the Company's control room. The DI capabilities also enable the advanced meters to capture

and compute new, highly detailed usage data that can be used to facilitate enhanced grid operations and enhanced customer offerings to support the efficacy of customer rate designs and programs. The DI capabilities of the advanced meters the Company is deploying, along with the necessary backend infrastructure to support the meters, open up a broad array of new uses that have the potential to transform how customers will use energy in their homes and businesses, as well as how Public Service will be able to optimize its AGIS investments.

Customer Facing DI Use Cases

The Company has released a mobile application called My Energy Connection that is available within the Apple and Google Play application stores. My Energy Connection leverages the HAN capabilities of the Company's meters. Customers may install the application on their iOS or Android mobile devices and use their My Account to securely login to the application. Customers connect with their mobile devices using the Xcel Energy Launchpad ("XEL") to enable the visualization of their real-time energy and demand data. For example, within My Energy Connection customers are able to see the impacts of appliances running while in their home. These capabilities are also available for third-party developers through the Software Development Kit (SDK), which was recently addressed by the Commission through Proceeding No. 23A-0471E. In that case, the Commission approved a settlement whereby the Company will, among other things, continue to offer an SDK through which third parties could register with GitLab to obtain relevant information and codes to develop customer-facing software or hardware; it would continue to provide XEL; and XEL would allow customers to "bring your own device." At their request, the Company has also actively engaged with third parties and encouraged the development of additional products that can enhance the Company's customer experience.

Grid Facing DI Use Cases

The Company is in the process of deploying several grid-facing use cases currently including EV Detection, High Impedance, and Location Awareness**.**

- **EV Detection.** DI capabilities can provide the Company with insights into where EVs are located and charging patterns of customers. This information can be leveraged to support system planning, load balancing, and infrastructure upgrade efforts based on awareness of EVs being added to a customer's load profile. This grid-facing use case will also enable the Company to become aware and proactively respond to possible service quality issues and encourage customers to participate in managed charging programs.

- **High Impedance.** This grid-facing DI-enabled capability will allow the meters to detect deteriorating or loose connections. Without those capabilities, such issues on the

secondary system, which carries power from transformers to meters, might only be detected if a customer notices a problem, such as flickering lights, or when they cause outages. By proactively identifying high impedance situations, the Company can promptly dispatch crews to proactively address the issue. A significant benefit of this capability is the prevention of outages, which enhances service quality for our customers and reduces the Company's outage response costs.

- **Location Awareness**. Knowing the precise location of the customer's premises and how it is connected to the grid is foundational to the Company's ability to plan and operate our system and to keep our customers informed. The mapping of customers to the system is maintained in our Geospatial Information System (GIS), which forms the basis for all of our system planning and modeling. When locations are not correctly mapped, that results in less accurate outage response and notification, grid management, and planning. The benefits of grid-facing connectivity use cases are improved accuracy in outage management and notification, and improved accuracy in planning and operational modeling. This application will correct the connectivity to mis-mapped customers, reducing this source of error. All processes that rely on the connectivity model in our GIS, including outage management, will benefit from the improved data. Going forward, this use case can also be used to maintain the accuracy of our GIS mapping after modifications to the secondary system.

ADVANCED OUTAGE MANAGEMENT

The Advanced Outage Management ("AOM") project will enhance the Company's management of the distribution system by consolidating multiple software platforms into a single consolidated distribution management platform. The project consists of deploying a single consolidated platform with that includes upgrading the current ADMS from version 3.7 to the newer version 3.9 version and a new outage management system. Consolidating functions into a single platform is an important step in the company's vision for managing a more complex electric grid that enables increasing levels of DER and meets multiple business objectives. It also supports the Company's advancement of visibility and control of the distribution system through more advanced outage management that includes advancing the use of AMI meter ping and outage detected and restoration events across the company's personnel and more advanced wildfire mitigation capabilities. It also tightly integrates outage management functions across the company with existing FLISR and IVVO applications supporting improved reliability and energy delivery for customers. Last, a consolidated distribution management platform is a key part of the company's broader efforts to modernize the electric grid with integrated technologies like field area network, AMI meters and automated field devices that together support the transition to a cleaner, more efficient electric grid.

OPERATIONAL TECHNOLOGY ASSET MANAGEMENT

The overall objective of the Operational Technology Asset Management ("OTAM") project is to standardize how Xcel Energy manages secure attributes of OT Devices in the field and equip the business with tools to implement and maintain secure device management practice. The OTAM project consists of deploying a device management platform that supports the management of OT devices such as managing settings and firmware.

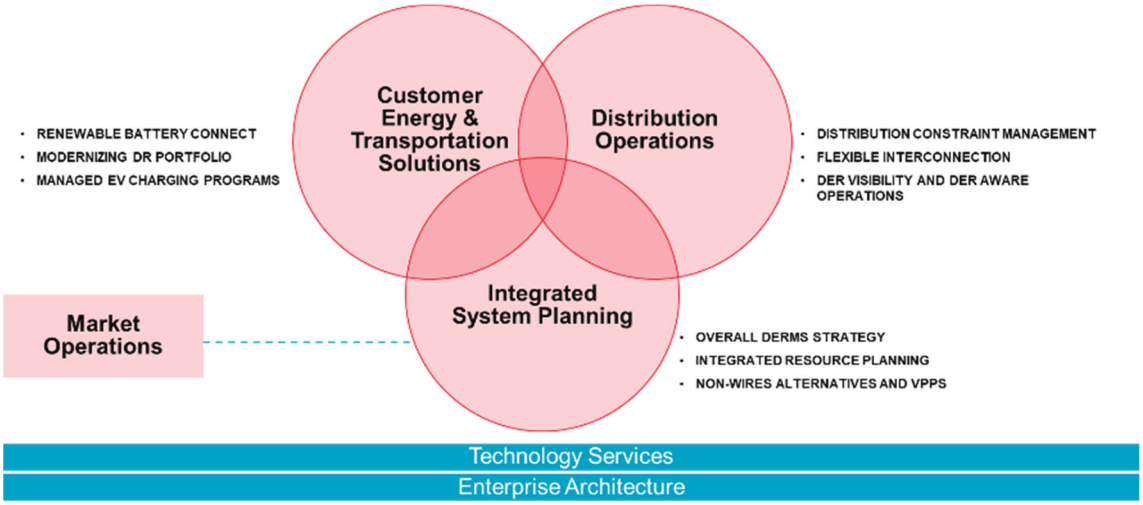
DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM

The Company views Distributed Energy Resource Management Systems ("DERMS"), and the business and customer processes which it can help enable, as a critical part of our strategy for planning and operating the grid, – particularly during this period of rapid change and demand growth in the industry. Specifically, DERMS can support several outcomes that benefit our customers and the grid including:

- Enabling higher penetration levels of DERs on the grid
- Supporting public policy objectives while maintaining safe, reliable operations of the grid
- Improving customer experience by offering more options to connect load and distributed generation
- Potentially reducing the cost and time to interconnect
- Increasing overall flexibility of the system
- Managing load in a way that minimizes costs and retail rate impacts

We are committed to developing DERMS capabilities and have made significant progress since the filing of the last Distribution System Plan and related proceedings. In 2024, the Company established a cross-functional DERMS team. The team consists of members from Customer Energy & Transportation Solutions, Distribution Operations, Integrated System Planning, Technology Services, and Enterprise Architecture groups as indicated in Figure 66.

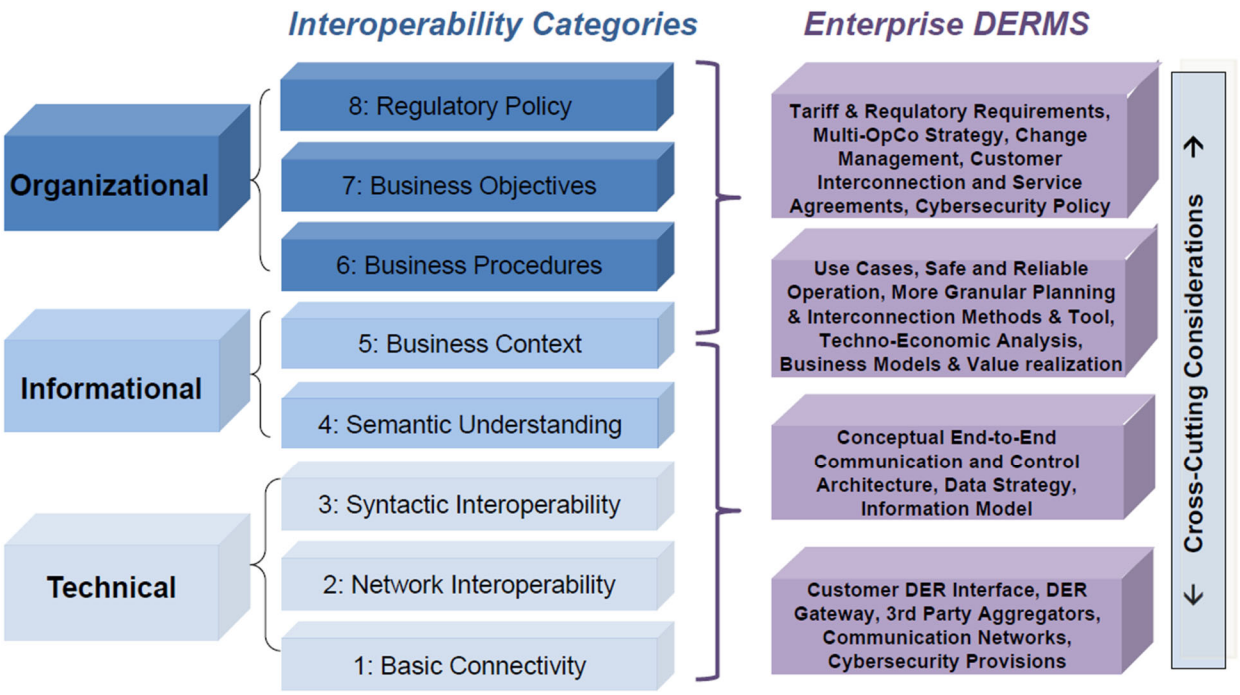
Figure 66: DERMS Organizational Interface



However, it is important to note that procuring DERMS software is one small component of enabling many of the use cases associated with DERMS. It is also critical to address the business process, organizational skillsets and change management, control and communication strategy and standards to DERs, and tariff/regulatory requirements associated with supporting DERMS capabilities. DERMS deployments must also consider evolution and more granular analysis required in the DER interconnection and study process as well as operational reliability and safety implications from actively managing constraints on the distribution system.

The GridWise Architecture Council ("GWAC") was formed by the Department of Energy ("DOE") to propose principles and accelerate the development and adoption of interoperability concepts and standards across all smart grid applications interfacing with electric systems. The Company has utilized the GWAC Interoperability Stack, as shown in Figure 67 as a general framework to illustrate the multi-faceted and cross-functional considerations and requirements for implementing an Enterprise DERMS. The stack outlines critical paths to facilitate the effective integration and alignment of devices, systems, use cases, processes, contracts, and organizational stakeholders within the electric systems to achieve regulatory policy and business objectives.

Figure 67: Application of GWAC Interoperability Stack to the Company's Enterprise DERMS



The GWAC interoperability stack depicted in the figure provides a construct for working towards Enterprise DERMS. Within this framework, organizational, business processes, and technology requirements must be developed together and in alignment to meet policy and customer objectives. Similarly, new devices and systems need to integrate with the existing infrastructure in a well-thought-out manner based on grid architecture principles, ensuring everything works together in a scalable and streamlined fashion. Currently, we are developing requirements related to OT software platforms, business processes, change management, and other key aspects of the Enterprise DERMS implementation. As we transition to a more sophisticated and dynamic planning and operational paradigm, enabled by an Enterprise DERMS, an intentional multi-faceted plan that is scalable is essential.

From a software perspective, the Company believes that there is not a single comprehensive solution that can meet all of its needs today. Therefore, the Company's approach to deploying DERMS software and use cases includes the procurement of a DRMS/Aggregator DERMS as well as the procurement and limited deployment of Grid DERMS. These initiatives are occurring on a parallel path, but we expect to integrate the two systems over time. As described above, supporting DERMS capabilities is not simplify deploying software and has many other considerations around people, process, and communication and control strategy with DERs.

DERMS Deployment Strategy

In developing our DERMS roadmap, the Company has considered and evaluated multiple deployment strategies relative to the current level of maturity of the DERMS market and our organizational capabilities. A table summarizing the potential deployment options that were explored by the Company is presented below. Based on the outlined factors, the Company has chosen Pathway 1, which reflects the pursuit of DERMs on a parallel path trajectory consisting of Aggregator DERMS and Grid DERMS.

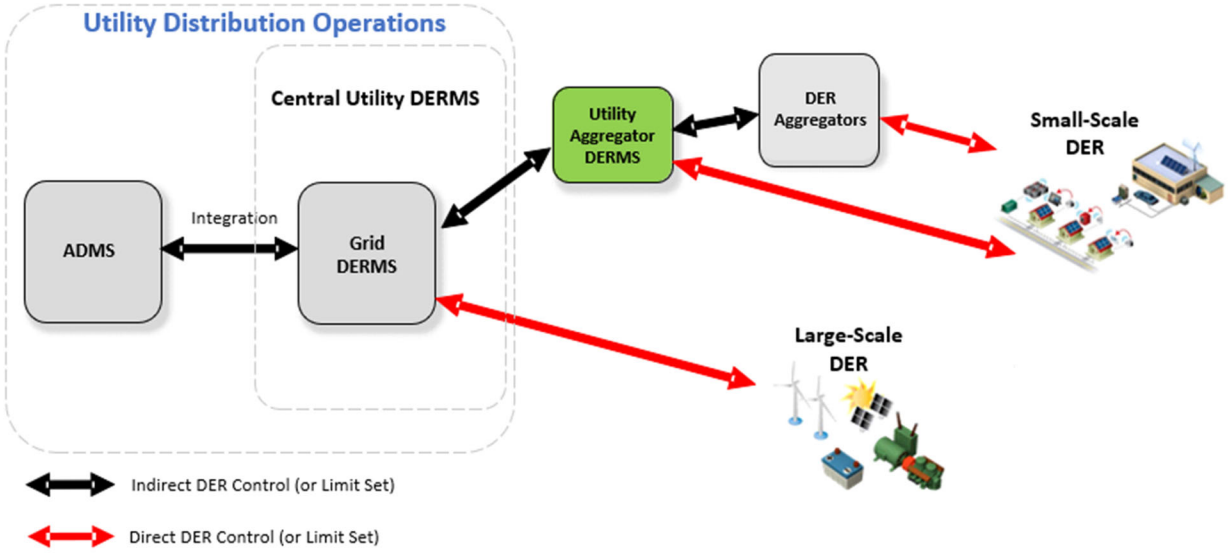
Table 30: DERMS Implementation Pathways

Pathway 1 – Phased Parallel Path Deployment	Alt. Pathway 2 – Consolidated Single Vendor Approach	Alt. – Pathway 3 – Vendor Dependent
• Phased Deployment of Aggregator DERMS, followed by the limited deployment of priority use cases for Grid DERMS (e.g. flexible interconnection, managed fleet charging, flexible load request). Depending upon the outcome of the limited deployment of Grid DERMS priority use cases, these use cases would potentially be integrated with other OT systems.	• Under the consolidated, single vendor approach, we would draft a comprehensive set of functional and non-functional requirements for both Aggregator DERMS and Grid DERMS into a single RFP	• Under pathway 3, the Company would continue to depend upon a patchwork of vendors all under separate software licensing agreement and management by multiple internal resources. This is how we manage the Renewable Battery Connect program today (i.e. relying on proprietary third party software).
Pros: • Allows us to "right size" the requirements and implementation to existing commitments and regulatory orders. • Focused agile/phased approach with this pathway. Start with a minimum viable product and build it by keep on adding additional capabilities/integration with other tools. • Optimizes around strengths and capabilities in each DERMS vendor • Allows Grid DERMS market to mature and the Company to develop experience and operational process and procedures	• Enhanced vendor accountability – a single vendor would be responsible for integration between Aggregator DERMS and Grid DERMS. • Potential integration and maintenance efficiencies	• Implementation speed
Cons: • Future integration risk – eventually we will need to integrate Aggregator DERMS with Grid DERMS.	• Longer timeline for implementation and failure to meet near-term regulatory deadlines for Renewable Battery Connect, Virtual Power Plant, etc • Unclear business value for Grid DERMS use cases. Many of	• Challenging to a have a consolidated, "single pane of glass" view of DER impacts on the system – leads to operational inefficiencies due to siloed and manual processes. •Contractual and labor inefficiencies (vendors

	• the Grid DERMS use cases have customer value (e.g. avoiding interconnection costs) but not always for a broader customer base • Substantially higher costs for both software licensing and implementation	• consistently charging more for less) •

This parallel path deployment approach is represented by the below high-level architectural diagram, Figure 68.

Figure 68: High-Level DERMS Architecture



Aggregator DERMS (Phase I DERMS)

The Company originally proposed procuring this capability in its inaugural Distribution System Plan (where it was referred to as DRMS) to support the evolution of the Renewable Battery Connect program that at the time was planned to support up to 10 MW and/or 850 battery systems. The initial intended purpose of the RFP was to implement the foundational technology platform to allow the Company to efficiently manage and expand the market for battery energy storage systems by consolidating management of batteries enrolled in the Renewable Battery Connect program into a single vendor platform.

However, in approving the acquisition of this foundational DER management platform, the Commission expressed concern that the platform should be capable of managing other DER types and use cases.

In addition to voicing these concerns in the decision approving the Distribution System Plan Settlement agreement, on September 18, 2023, the Commission opened an examination of third-party provision of gas demand response services, virtual power plants, and neighborhood electrification. The Company participated in a series of workshops throughout this proceeding. Ultimately, the Commission concluded that the expected pilot program objectives for Aggregator DERMS (Referred to as Phase I DERMS) should include facilitating the delivery of demand response, enhancing the customer experience, and shaping load to better conform with supply.

As a result of this Commission guidance in both venues, the Company significantly expanded the scope and requirements of the DRMS solicitation (which was subsequently renamed Aggregator DERMS.) While the Company is still working to complete the DRMS compliance report consistent with the Commission's decision in the last Distribution System Plan, given that we expect Aggregator DERMS to serve as a foundation to achieving several objectives of the Commission, we are no longer considering this to be a pilot. Rather, we view this platform as foundational to helping to facilitate many of the objectives of SB 24-218, including, but not limited to establishing a VPP tariff.

The Aggregator DERMS evaluation team conducted an initial market assessment of 32 vendors and published the Aggregator DERMS RFP to seven vendors. The Company conducted a solicitation of third-party vendors for proposals for an Aggregator Distributed Energy Resource Management System ("ADERMS") in second quarter of 2024. The Request for Proposal ("RFP") was the culmination of two years of work that developed over one hundred use cases and over one thousand functional requirements.

Proposals from five vendors were received on or prior to the deadline date of June 3, 2024. Following a detailed scoring process, a shortlist of three vendors were invited to participate in a functional 'deep dive', including a full day demonstration of their platform focused on 12 use cases identified and shared prior to the meetings.

At this time, the intent of the Company is to incorporate the ADERMS into its broader enterprise DERMS strategy, which aims to leverage DER for various purposes, including load modification and grid services. The Company anticipates this platform will be a critical foundation for future DER management programs.

Grid DERMS (Phase II DERMS)

Over the last year, the Company has been evaluating and prioritizing use cases for Grid DERMS that align with the Company's and Commission's objectives for Phase II DERMS set forth in the VPP M Docket (23M-0466EG). These activities have included conducting internal research, benchmarking with peer utilities, vendor due diligence and other related activities. Our research has affirmed that many, if not all, utilities are taking a use case

driven approach to deploying DERMS starting with a more limited deployment at first. This is in contrast to more typical enterprise deployments for other operational technology (e.g. ADMS), where it is necessary to support the operation of the entirety of the system. A targeted, use case driven approach has allowed utilities to rapidly deploy and enable use cases relative to more traditional enterprise-wide software deployment approaches, while also minimizing stranded technology risk. This approach is important given the relative immaturity of the DERMS market as well as the limited broad-scale operational experience with more sophisticated real-time monitoring, control and DER device and system interoperability on the distribution system.

The Company collaborated with EPRI on a project to develop a detailed set of requirements for Grid DERMS, based on identified priority use cases. This included functional and non-functional requirements for Grid DERMS platform, covering both normal and abnormal circuit configurations. The requirements assumed integration of Grid DERMS with other operational systems, such as ADMS, and downstream with DERs and EVs through DER gateway platforms. Key criteria for the requirements included functionality, scalability, reliability, speed, and performance. The Company received a Technology Transfer Award from EPRI in recognition of its exemplary collaboration on this project.

Grid DERMs Use Cases

Consistent with the Settlement Agreement in the previous Distribution System Plan, the Company is presenting its high-level use cases associated with an upcoming limited deployment of Grid DERMs. However, the Company notes that it is still working on more detailed requirements gathering process to fully reflect related technology, process, and organizational change management.

After extensive evaluation, the Company has prioritized three use cases to demonstrate as part of an upcoming limited deployment of Grid DERMs. These use cases are Flexible Interconnection for Distributed Generation, Flexible Connection for EV Load.

Table 31: DERMS Use Cases and Intended Policy Goals

Use Case	Intended Policy Goals
Flexible Interconnection for Distributed Generation	• Enable lower cost and/or more timely interconnection of large-scale distributed generation
Flexible Connection for EV Load	• Enable lower cost/and or more timely connection of specific types of load that may not require firm capacity for all hours of the year

The two use cases support more flexible and dynamic approaches to constraint management that have the potential to provide benefits to our customers and the overall system. The Flexible Interconnection use case will build upon the learnings and analysis that have resulted from the Company's Flexible Interconnection Settlement commitments from the previous Distribution System Plan as discussed further in the Flexible Interconnection section below.

While not a use case at this point, the Company anticipates leveraging Grid DERMS to ensure safe and reliable operations relative to the Dispatchable Distributed Generation requirements that were established through SB 24-207. However, we understand that several key details of this statutory requirement have not yet been detailed and expect to evolve potential DERMS capabilities as these programmatic requirements are defined.

Consistent with the Company's comments in Proceeding No. 23M-0466EG, the Company has been conducting technical diligence on potential Grid DERMS solutions. Additionally, the Company is working to establish the initial requirements for the process, people, and procedures that will be needed to ensure the Grid DERMS can be operated in a way that the Company has the proper skillsets and procedures such that it does not introduce unnecessary complexity to maintaining the safety and reliability of the distribution system. To that extent, the Company has been working on several supporting initiatives. These include:

- Conducting more granular time series interconnection analysis to understand distribution system constraints and flexible interconnection mitigation strategies;
- Coordinating with DER developers and plant controller vendors on potential control architectures;
- Developing initial communication and control standards and requirements for DER devices which would provide the critical link between Grid DERMS and DER plant controllers;
- Developing draft contracts for flexible interconnection that would modify the current interconnection agreement terms and conditions;
- Working with EPRI to develop functional requirements for Grid DERMS;
- Identifying and securing grant opportunities and funding opportunities to reduce the cost of DERMS implementation; and
- Benchmarking with peer utilities to better understand vendor capabilities and lessons learned.

Lastly, the Company will continue to advance its long-term DERMs strategy that encompasses both Aggregator DERMS and Grid DERMs. Importantly, this includes understanding the prioritized list of use cases that will need to be implemented as part of a strategic roadmap, with particular focus on the organizational structure and individual skillsets that will be needed to support operation of DERMS-related use cases that extend beyond just the software itself. The Company plans to issue a request for proposal in 2025 for a strategic consultant engagement to help support both the short-term and long-term needs. Other key objectives include:

- Detailed analysis on the feeder by feeder needs for DER management that may require more advanced monitoring and control needs;
- Integrated strategy including VPP, DSM, and Renewable Programs;
- Current and future Policy and Regulatory considerations; and
- People and organizational structure recommendations.

The Company also underscores the importance of creating a strategy that focuses on value driven use cases that is people and process forward that technology enables and supports. There will also need to be considerations around the level of complexity that is achievable on the distribution system such that it does not impact the safety and reliability of the grid.

Alignment Between VPP Strategy and DERMS Strategy

SB 24-218 requires that the Company file an application for a VPP tariff by February 1, 2025. The Company anticipates leveraging the ADERMS platform to facilitate the offering. Initially, we anticipate the VPP tariff will reflect the provision of bulk system benefits on a pay-for-performance basis. More detail will be provided in that separately required filing. As the Company enhances its dynamic grid management capabilities through ADERMS and GDERMS, we expect to further develop our VPP offerings.

Alignment Between DERMS Roadmap and Flexible Interconnection and Flexible Load Connection

Flexible interconnection of DERs, especially large PV plants and EV fleet charging, are priority use cases for DERMS, taking advantage of the fact that the hosting capacity is both time and location dependent. The objective of the flexible interconnection use case is to manage equipment capacity and voltage constraints in the distribution system during both normal and abnormal scenarios.

The role of the DERMS in this use case is calculating permissible limits, communicating them to the respective DER or EV sites, and overseeing their operation. This ensures compliance with the limits and allows for corrective or fail-safe action if needed, using a control architecture like the high-level architecture shown in Figure 69.

Figure 69: High-Level DERMS Architecture for Flexible Interconnection Use Case



DERMS Roadmap: Near-term Next Steps

Below is a roadmap, with near-term next steps, for Aggregator DERMS:

- Project kick-off and planning services
- Functional requirements workshop and designs
- System Integration testing ("SIT") and User Acceptance Testing ("UAT")
- OEM integration for load control and telemetry
- Organizational Change Management ("OEM") changes to procedures and workflows
- Execution and deployment to production environment
- Production Implementation Testing ("PIT")
- Continuous improvement

Below is a roadmap, with near-term next steps, for Grid DERMS:

- Finalize requirements and use cases
- Issue RFP for third-party consultant
- Complete software vendor due diligence

- Develop contractual and tariff provisions for flexible interconnection and load

Prime Time VPP

Prime Time VPP, as outlined in the federal funding discussion and earlier in this section, offers a unique opportunity to showcase the clean energy future framework through the deployment and operation of a VPP. As part of this project, the Company will develop and test technologies, personnel, and processes that enable innovative ways for customers to participate in grid services. This project aims to provide value to both the grid and customers while meeting regulatory and business objectives. The team will integrate and coordinate DERs through distributed energy systems to perform valuable grid functions to meet distribution and bulk system needs. This will inform successful frameworks for future VPPs, including enabling and operating a clean energy future with diverse communities.

This project aligns with the Company's DERMS roadmap and plans, which include implementing an Aggregator DERMS and Grid DERMS. Ultimately, these platforms will integrate to form the Company's Enterprise DERMS, supported by the necessary personnel, business processes, and DER communication and control strategies.

Flexible Interconnection

Flexible interconnection is a strategy that can potentially allow DER to connect in constrained areas without some of the distribution upgrades typically required. This is achieved by implementing real-time, schedule-based control that can dynamically change the output on DER in relationship to grid constraints. Flexible Interconnection has been deployed to a limited extent in North America in a manner that has mostly been targeted at large-scale distributed generation (e.g. >1 MW). This is because the costs of these projects are typically able to absorb the incremental costs associated with the hardware and software to enable flexible interconnection. Further, the more sophisticated control schemes enabled by this approach can generally provide more hosting capacity in a given area for larger projects.

There are significant step changes involved with moving to flexible interconnection schemes. Below we describe some of the systems and components the Company has been evaluating.

DERMS is a software OT/IT system that is one important aspect of a mature and more wide-scale flexible interconnect process. Flexible interconnection strategies also require new and innovative changes in other important operational areas such as device communication, system protection and new grid devices such as DER gateways and DER plant controllers. Other technical considerations, such as system architecture, interoperability with central systems such as FAN, ADMS and GIS, system reliability and

resiliency aspects, need to be evaluated and specified. As will be discussed in more detail below, new processes and procedures are needed for personnel and operations. Policy considerations also influence flexible interconnect approaches significantly. The deployment of flexible interconnect strategies needs to be undertaken in measured steps. Each step would have to demonstrate various testing objectives and metrics before moving to more sophisticated complex steps.

The Company is undertaking the testing, vetting, and demonstration of many of the components needed to limit constraint violations and enable flexible interconnection. These components can be used while DERMS evaluation and development is underway and will become essential components of a DERMS once deployed. For the sake of discussion, we describe this stage as Stage 1: Pre-DERMS Flexible Interconnection. This can be considered a “walk” phase in a walk/jog/run analogy to deployment. The components currently being deployed and evaluated for performance include:

1. System measurement/monitoring devices to provide real-time feedback of system conditions.
2. DER Gateways to link utility networks with DER plant controllers and load management systems.
3. Use case implementation combining system measurement, DER Gateways, and existing ADMS functions.
4. Enhanced study process to inform interconnection agreements and dispatch schedules.

System Monitoring

The Company has experience with multiple suppliers deploying SCADA-enabled monitoring devices of various system conditions. The most immediate need is for voltage or current monitoring of constraint locations, which can be accomplished using line sensors tied to a gateway. The monitor’s gateway would watch for either voltage or current thresholds to be breached and command curtailment signals to a downline DER device as needed. Control by the system monitor is straightforward when curtailing a single DER, but it is unclear at this point if multiple DER could be curtailed simultaneously in a fair, safe and reliable manner. However, a DERMS would be capable of DER grouping and could curtail multiple DER. For the period of time until this DERMS function is enabled, less aggressive curtailment methods will need to be deployed.

DER Gateways

When constraints can be monitored using line sensors accompanied by SCADA, the monitor can act as a master that curtails downstream DER and Load controls. The gateway is a remote computer installed at the DER/load site that acts as a utility agent

coordinating communication and curtailment signals, including schedules. The DER/load would need to agree to provide site status information, accept control signals from the gateway, and revert to a default operating state if communications are lost. Successful deployment of gateways also requires the third-party DER operator to integrate its devices under a single site controller. Xcel Energy's assessment of current DER deployments is that not all developers are deploying site controllers and they are still climbing a learning curve to understand site controls and associated requirements. Flexible interconnection requires functionality, software, and hardware that many developers have never considered, so significant engineering analysis and time may be required for each developer to enable gateway integration and flexible interconnection.

Existing Xcel Energy SCADA designs using Private LTE, fiber, or radio mesh networks could enable fast communication, monitoring and control between grid-edge devices, specifically between monitors and gateways.

Use Case Implementation

The gateway also provides a means to program more sophisticated logical functions. While the logical functions of DER gateways are not as sophisticated as DERMS, they provide a means to demonstrate limited use cases directly with developers. System constraint prevention is a common issue today to Xcel Energy and can be mitigated using the components just outlined.

Cybersecurity Considerations

Flexible interconnection capability is enabled with a network of SCADA devices which take part in the same sequence of operations. A loss of a device will break the sequence, requiring failsafe dispatch setpoints and/or operating modes when communications are lost. This failsafe will be coordinated by the gateway. Additionally, the gateway communicates with a third-party controller which can tie to unknown external systems. To avoid cybersecurity threats from the customer controller, a serial connection is used as the link between the gateway and customer controller. A serial connection provides a secure barrier against external access, avoiding the access threats associated with TCP/IP connections.

Enhanced Study Process

Initial review of the issue in 2024 showed that the flexible interconnection study process is longer and more costly than traditional impact studies. Flexible interconnection study outputs must, at a minimum, provide enough detail to estimate financial impacts for the DER developer so that a flexible interconnection agreement can be reached. In addition,

the study should provide a schedule that can be used as an alternative means of curtailment when real-time control is unavailable.

Upcoming Demonstrations

Flexible interconnect includes not just DER interconnections but also typical load and dispatchable generation interconnections. The Company is pursuing demos of all three types:

- The Company is working with a vendor who operates solar plant controls for many Public Service solar developers to create a standard plant controller design to enable flexible interconnect at future locations. A pilot demonstration of this design will be installed at the Company's existing Arapahoe Community Solar Garden ("CSG") and demonstrated alongside other flexible interconnection components.
- The Company has existing battery assets to test flexible dispatchable generation functions. In addition, there are existing interconnection applications from dispatchable generators which may reveal system constraints that require flexible control. The Company intends to pursue flexible interconnection with these locations if needed.

The Arapahoe CSG is the most progressed flexible interconnect project effort so far. This project is expected to run through 2025 with completion of flexible interconnection use case testing planned to be complete by the end of 2025.

Implementation of flexible interconnection will increase the number of SCADA devices being deployed and maintained by distribution personnel and will expand distribution's communications networks. Before a broader flexible interconnection strategy is deployed, additional diligence must be conducted around: 1) Refinement and standardization of flexible interconnection studies; 2) Understanding resource requirements, new business processes, training and change management requirements; 3) refining next steps in future Phases; and 4) additional technical and security requirements.

Flexible Interconnection Tariff.

SB 24-218 requires the Company to propose the use of an optional flexible interconnection or energization tariff as an alternative to a system upgrade. The Company will meet this filing requirement in 2025 and the demonstrations and other testing, validation, and study have been informative in shaping the concepts around this offering.

The Company is also planning to demonstrate flexible load applications for managed EV charging through the Innovation Portfolio associated with the TEP. The Company plans

to propose specific projects in 2025 to advance this objective via the 60-day notice process in its TEP proceeding.

PILOTS, DEMONSTRATION PROJECTS, AND PROGRAMS

As the distribution system becomes more complex, it will require new tools, processes, and technologies to both plan and operate. This section provides an overview of existing pilots and programs, and pilots and programs proposed in other proceedings as well as the concepts the Company is bringing forward as part of this DSP.

DSP Third-Party Pilot Solicitation

In November 2023, the Company reviewed and partnered with the DSP Stakeholder Technical Working Group to review the process and interest areas prior to issuing the solicitation. This process included working with stakeholders to develop the Distribution Pilot Evaluation Criteria as well as designing an Initial Concept submission paper template. The Company conducted a solicitation for third-party distribution pilots in 2024.

The Company solicited ideas and proposals for pilots to address the following distribution system needs and technical objectives.

- Integrate Distributed Energy Resources (DER), Non-Wires Alternatives (NWA) and emerging technologies
- Improve distribution system performance
- Minimize distribution system costs
- Increase distribution system reliability
- Increase distribution system resiliency
- Reduce greenhouse gas emissions including from reduced curtailment of renewable energy
- Provide benefits to disproportionately impacted communities

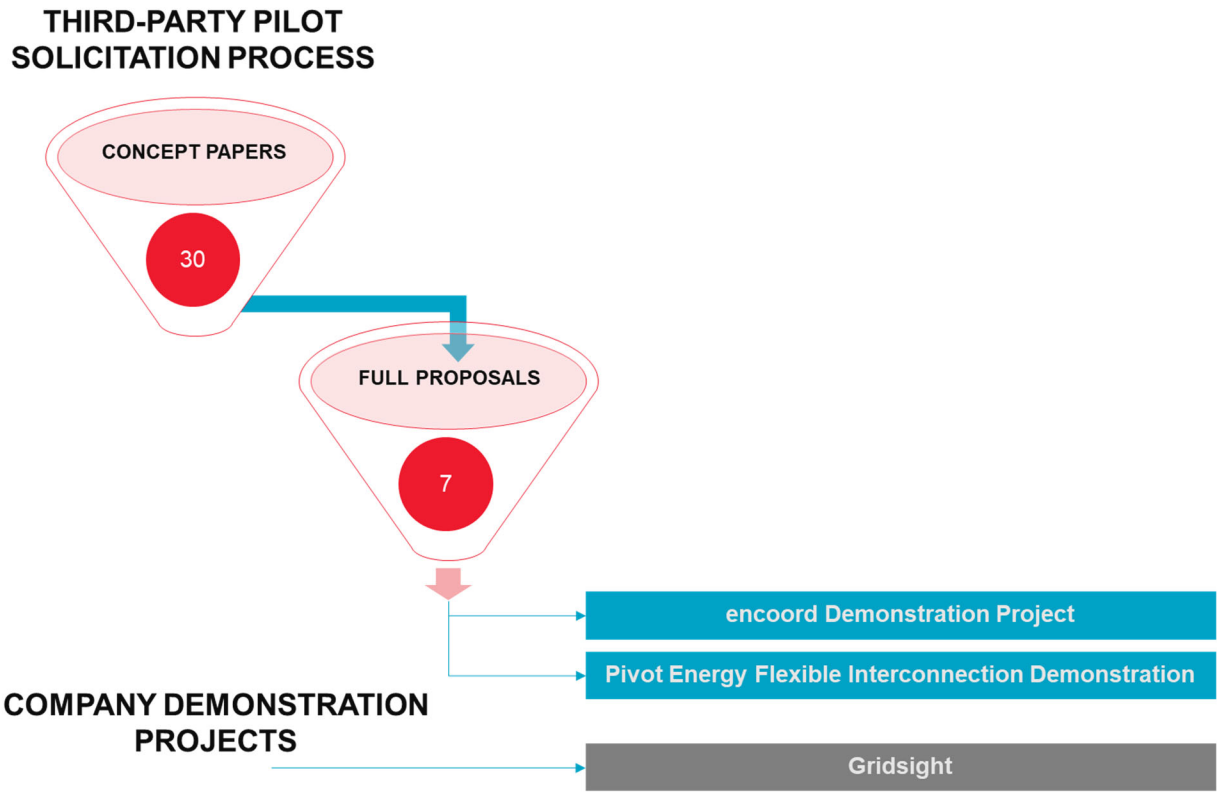
Within meeting these technical objectives, the Company indicated additional Areas of Interest. Proposals were encouraged to address one or more of these focus areas, which are summarized below.

- Area 1: Outage Prevention, Restoration and Resilience to Provide Safety and Reliability (including predictive analytics).
- Area 2: System Visibility and Control to Prepare for High Renewables and DER Future

- Area 3: Increase utilization of distribution capacity due to high electrification and DER growth
- Area 4: Machine Learning and Artificial Intelligence to Grow Novel Approaches to Future Applications

The solicitation process resulted in 30 unique proposals. The Company short-listed seven of these proposals based upon a review process that included members across several organizations in the Company. A high-level overview of the process is provided below in Figure 70.

Figure 70: Overview of Pilot and Demonstration Project Process

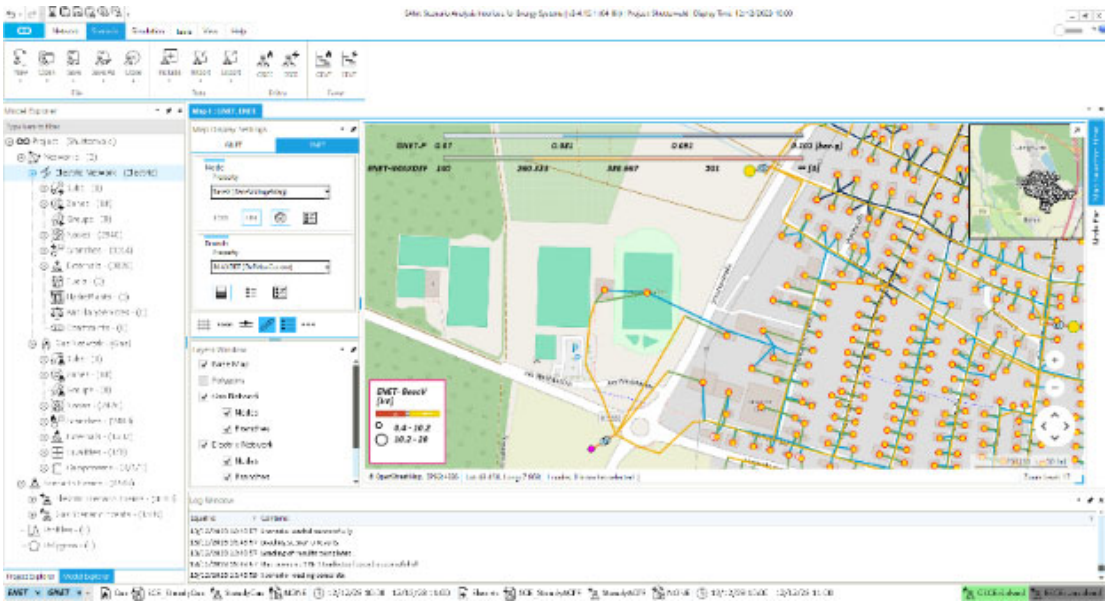


This pilot solicitation has been successful in creating a distinct opportunity for third parties to propose ideas and transparent to DSP priorities. From the shortlisted proposals, the Company found value in a proposal from Pivot Energy and encoord. However, the Company did not feel that these proposals met the standards established by the Commission for pilots under applicable DSP rules. The Company is nevertheless moving forward with exploring these concepts though other means. Further discussion is provided in the Direct Testimony of Beth Chacon.

encoord - Least-Cost Electrification Planning via Integrated Gas and Electric System Simulations Emphasizing Non-Wires Alternatives and Disproportionately Impacted Community Benefits

Through the third-party solicitation process the Company conducted in 2024, the Company received a proposal from encoord Inc., a Colorado-based company. [E]ncoord is an energy modeling software provider that focuses on integrated energy planning across electric generation, transmission, distribution, and gas networks. This cross-commodity analysis is facilitated through their Scenario Analysis Interface for Energy Systems (SAInt) tool. SAInt models electric distribution systems with unbalanced power flow, electric transmission networks with balanced power flow, gas networks with hydraulic simulations, and electric generation expansion and dispatch with capacity expansion and production cost modeling. In other words, SAInt is an integrated platform that will allow the Company's gas and electric planners to better collaborate on alternative solutions to infrastructure (e.g. non-pipeline alternatives).

Figure 71: A screenshot of the SAInt software graphical user interface, with simulated electric and gas networks.



While the Company is not bringing this proposal forward as a formal pilot under the Commission's DSP rules, we nevertheless recognize the value that this type of capability could provide from an integrated system planning perspective and are moving forward a demonstration project with encoord.

The goal of the demonstration with encoord is to co-optimize the consideration of non-pipeline alternatives across our gas and electric systems. In other words, identifying

candidate areas for NPAs on the gas system that can be accommodated at minimal cost of upgrade to the electric system. A full description of the demonstration project is provided as Appendix 5 to the plan.

The Company sees significant value in this type of integrated approach. We anticipate beginning this project in Q4 of 2025 after completing the implementation of a more advanced electric load flow modeling software tool ("CYME").

Gridsight – Technical Analysis to identity Opportunities for Increasing Network Flexibility

Gridsight is a software and analytics platform that was founded in Australia. They help distribution network operators manage an increasingly complex grid and maximize their hosting capacity.

Leveraging grid-edge data, they provide system constraint visibility, help assess the potential for Non-Wires Alternatives (NWA) such as grid-aware flexibility, and help enact flexibility at scale. These concepts are foundational to enabling greater DER penetration and removing interconnection bottlenecks, as demonstrated by utilities in Australia with over 30% household rooftop solar PV penetration.

Gridsight complements traditional power-flow-based modeling and centralized control strategies (e.g., ADMS, and Grid DERMS). It adopts a bottom-up approach, using machine learning to scalably analyze grid-edge telemetry from millions of devices across the network and calculate optimal DER operating limits.

The Company is partnering with Gridsight to enhance distribution system visibility and inform its NWA strategies. Gridsight and Company will run hosting capacity scenario analysis and leverage AMI data to incorporate grid-edge, transformer, conductor, and feeder-level dynamics into flexibility and upgrade decisions. This includes exploring the feasibility of NWAs to enable scalable DER interconnection while minimizing infrastructure costs.

In the screenshot below, Figure 72, hosting capacity and DER operating limits are calculated dynamically, demonstrating how grid-aware flexibility can mitigate constraints and maximize DER output. On this day, an additional 435kWh of renewable solar energy was released for these 37 customers, compared to conservative static limits.

Figure 72: Dynamic Operating Envelope Simulation Report - Active Management of Residential PV



This project will be foundational in informing the deployment and monitoring strategies of Company's flexibility initiatives. The Company will initiate this work in early 2025 and fund the project through its Rapid Innovation Framework.

The Company will be initiating this work in early 2025 and funding the project through its Rapid Innovation Framework.

MICROGRIDS AND INNOVATIVE TECHNOLOGIES

Community Resiliency Initiative ("CRI")

The CRI supports communities throughout Public Service's service area by providing battery energy storage system ("BESS") enabled microgrids in key locations.[49] Communities are developing resiliency plans that better prepare them for extreme weather events such as severe storms, wildfires or floods. Resiliency strategies are designed to anticipate severe disruptions to day-to-day life, invest in critical infrastructure and systems to help in times of crisis, and hasten recovery after an event. One of the most critical objectives of a resiliency plan is ensuring a secure power supply for critical infrastructure, such as evacuation centers.

The BESS systems provided via the CRI will be able to provide back-up power to critical infrastructure during outage events while allowing for the energy storage asset to provide grid services during non-emergency operation. The BESS systems were sized to meet each facility's load and to provide grid value at the interconnection point. Existing or planned solar provided by the Customer will have the capability to charge the BESS during and extended outage, providing additional resiliency. Project sites include 1) Alamosa Recreation Center; 2) Arvada Center for Arts and Humanities; 3) Denver International Airport; 4) Denver Rescue Mission; 5) National Western Center; and 6) Nederland Community Center.

Status Update

Projects at Alamosa Recreation Center, Nederland Community Center, Denver Internation Airport, and the Arvada Center for Arts and Humanity completed construction and are in final stages of vendor software updates to enable all microgrid functionalities. All remaining projects are in the final stages of construction preparing for commissioning in early 2025.

The Company continues to view the lessons learned from these delays as an opportunity to develop mitigations and process improvements for other CRI and energy storage projects on the distribution system, as well as any future newer technology and permitted projects. These projects are unique for both the Company and many of our partner communities and so understanding the issues that have developed in this initial phase of projects will help future projects be implemented more efficiently.

[49] Proceeding No. 19A-0225E.

TRANSPORTATION ELECTRIFICATION PLAN - INNOVATION PORTFOLIO PROJECTS[50]

The Company's inaugural 2021-2023 Transportation Electrification Plan ("TEP") was approved in March 2021 in Proceeding No. 20A-0204E and contained a comprehensive suite of electrification programs intended to compliment State of Colorado policy goals, build on efforts already taken, and address gaps or challenges in the EV market. The Company's initial TEP included the Partnerships, Research, and Innovation ("PRI")[51] portfolio with objectives of increasing customer access to EVs by minimizing costs, increasing environmental benefits, and gaining technology insights. Through the 60-Day Notice process, the Company proposed and has since launched numerous Innovation projects. As required by Decision No. C24-0223 in Proceeding No. 23A-0242E, the Company's 2024-2026 TEP, a status update for all Innovation Projects launched during the initial TEP was filed with the Commission in July 2024.[52] These projects are expected to conclude in 2025 with final reports filed for each project. Innovation project updates are summarized below.

Residential Resiliency and Managed Charging Project

The Residential Resiliency and Managed Charging Project is a collaborative study conducted by researchers at NREL on the impacts of residential EV charging on the distribution grid under various managed charging scenarios. The results of this study will be used by the Company to develop a "Charge Ready Tool" to help prepare the distribution grid for increasing levels of EV adoption in our service territory. This tool, called EVI-Dist, simulates different EV adoption and charging scenarios on select Company feeders to study the impact of these loads on the electric distribution system. The Project will study the impacts of EV home charging for one or more customers sharing the same transformer and secondary circuit under varying conditions of load, load diversity, and customers/transformer, as well as varying lengths of secondary circuit, secondary conductor sizes, transformer sizes, and other variables such as solar plus storage and TOU rates.

Status Update

[50] For more information about current and past 60-day notices associated with the Transportation Electrification Program pilots and projects, see https://www.xcelenergy.com/company/rates_and_regulations/filings/transportation_electrification_plan

[51] The Partnerships, Research and Innovation Portfolio is now referred to as the Innovation Portfolio in the 2024-2026 TEP.

[52] See the 2021-2023 Transportation Electrification Plan Status Updated as filed July 26, 2024, in Proceeding No. 23A-0242E.

In 2024, NREL completed an analysis to inform project requirements and strategies. This included the review and study of charging behavior within Colorado, EV adoption rates, travel itineraries, and vehicle energy consumption. This information helped inform estimated charging times that NREL used to determine EV plug-in vs. plug-out time distribution.

NREL developed an EV charging hardware testbed to collect EV and charger data from the Hyundai Ioniq5 and Ford F-150 to provide additional data to inform development of the first tool version, EVI-Dist, Lite alpha (0.1.0a). In June 2024, NREL delivered the first iteration of its modeling tool, Lite alpha (0.1.0a), to the Company. Public Service is currently testing the tool and providing feedback to NREL. Analysis from this tool will help inform the first version of the Company's EVI-Dist tool.

A second version of the tool, EVI-Dist, Plus alpha (0.1.0a), is in development and includes additional simulation and modeling capabilities. Training for the tools will continue into the first quarter of 2025. The Company's Distribution team will provide user feedback for continued development of EVI-Dist tools until the conclusion of the Project.

The Company plans to conclude this project in 2025.

V2X and Resilience Project

The V2X and Resilience Project has two phases, the first phase being a feasibility study[53] and the second phase being V2X demonstrations. The second phase of the Project was designed to fund and test the installation and performance of V2X-capable chargers in three key use cases: Vehicle-to-home ("V2H"), Vehicle-to-Building ("V2B"), and Vehicle-to-grid ("V2G"). The goal of the limited scale deployment was to identify and demonstrate the most valuable use cases of these technologies. Participants in the program provide critical data points from beginning stages to completion, including cost analysis, driver feedback, energy consumption, and customer experiences. The Company anticipates that this data will offer integral insights on the implementation and impacts of V2X technologies across a variety of use-cases. Learnings from pilot participants are collected to provide insights for deploying future V2X projects.

Status Update

The V2X and Resilience Project launched in 2022. Phase 1 - V2X Feasibility Study Project was completed in June 2023. Installations within the V2X Project are in varying stages of completion.

[53] Public Service previously shared the results of the feasibility study, titled The Potential of V2X, as Attachment CAG-2 to the Direct Testimony of Andre Gouin in the Company's 2024-2026 TEP, Proceeding No. 23A-0242E.

The V2H demonstrations installations were completed in 2023 at two residential customer homes as well as Public Service's SolarTac test facility. All V2H bidirectional chargers are installed and functional. Public Service continues to monitor and evaluate equipment performance at the residential locations and proactively test equipment at its SolarTac test facility, where the Company can proactively test the equipment without unnecessarily impacting the two participating customers.

The two V2B demonstration projects are currently at different stages of completion. At the Molly's Spirits project site in Denver, the bidirectional chargers have been installed, commissioned, and are actively being used by the business's fleet of Nissan Leafs. The bidirectional chargers at the Boulder Housing Partners site are also installed and fully commissioned. The V2B-capable vehicle has been delivered by project partner Colorado CarShare and is currently in use by community members. For both V2B sites, Public Service has provided Permission To Operate, with restrictions on V2B capabilities due to system performance challenges. Upon resolution of these challenges, Public Service will remove any restrictions and allow full V2B capability.

For the V2G demonstration at Peak to Peak Charter School in Lafayette, Colorado, installation of the bidirectional charger was completed in 2024 and the V2G-capable school bus has been delivered to the site. The bi-directional charger is functional, with updates being made for a remote battery discharge signal that originates from our back-office systems. This will be completed in 2025.

The Company is using these projects as 'real world' opportunities to identify gaps in the existing interconnection application and approval process for V2X projects that must be addressed to better accommodate and streamline V2X project approvals in the future. The Company continues to track these projects through the interconnection process and identify opportunities to update the process to better accommodate future V2X projects.

Municipal Refuse Fleet Electrification Project

The Municipal Refuse Fleet Electrification Project offers rebates for the purchase or lease of an electric refuse truck, chargers and required infrastructure to be used within the fleets of waste management vehicles. The primary objectives of the project are to: 1) provide advisory support and funding for vehicles and infrastructure to support electrification of refuse fleet vehicles; and 2) to study refuse fleet electrification by understanding how vehicle performance changes from varying regions within the Company's service territory.

Participants in the program are providing critical data points on various topics from beginning stages to completion, including cost analysis, driver feedback, energy consumption, and customer experiences, offering integral insights on the electrification of refuse waste management vehicles or other heavy-duty fleets with specific use cases.

Learnings from project participants are being collected to provide insights for the potential scaling of refuse electrification projects for other waste management fleets regionally.

Status Update

The Municipal Refuse Fleet Electrification Project launched in July 2022. The Project had seven applicants, resulting in five participants based on project scoring and available funding. Current participants include Denver Department of Transportation and Infrastructure ("DOTI"), Eco-Cycle, Waste Management, Waste Connections, and Republic Services.

Projects are currently in varying stages of completion. Republic Services has reported a successful project launch and has its vehicle in service. Republic Services of Denver expects to replace all residential collection fleet with EVs by end of 2024. Eco-cycle received and placed its vehicle into service in September 2024. Waste Connections is nearing project completion and once vehicle wrap is finalized, its vehicle will be ready to operate and will be added to its operational fleet.

Denver DOTI and Waste Management are awaiting vehicles to be delivered. DOTI has faced significant delays in the delivery of its vehicle but has elected to use mobile chargers so the project will be active as soon as the vehicle is procured. Waste Management has received the vehicle chassis, and the vehicle is going to the body provider for completion.

The Company plans to conclude this project in 2025.

Electrify Paratransit Mobility Project

The Electrify Paratransit Mobility Project offers rebates for the purchase or lease of medium-duty ("MD") EV paratransit shuttle buses, chargers, and infrastructure for paratransit fleet operators.

The project's main objective is to provide advisory support and the required funding to study how to reduce upfront operational costs of electrifying MD paratransit shuttle buses and to provide insights into possible future expansions of electrified paratransit operations. Participants are required to provide critical data points from beginning stages to completion, including cost analysis, driver feedback, energy consumption, and passenger experiences.

Status Update

The Electrify Paratransit Mobility Project launched in July 2022. The Project had five applicants, resulting in three participants based on program scoring and available funding. Participants include Laradon, Northeast Transportation Connections (NETC), and Via Mobility.

Participant projects are in varying stages of completion, with all projects targeted for completion by December 31, 2024. Participants received project support, fleet advisory services, and funding from the Company as a part of the Project. Project participants were responsible for vehicle procurement, charger and infrastructure installation and commissioning. Participants' projects are in varying stages of completion:

- Northeast Transportation Connections has been successfully operating two vehicles starting in January 2024. They have communicated that the shuttle vehicles have been performing as anticipated and they have received favorable feedback from their riders on the overall experience. The participant has communicated to the Company that they are concerned about the future of their pre-paid service agreement from the manufacturer, Lightning e-Motors, which has since filed for bankruptcy, due to lack of support or warranty on the vehicle. An additional challenge to note, the project data collection was being sourced through Lightning e-Motor's Insights data dashboard through a five-year subscription and access to that data ceased as of February 2024.
- Laradon received funding for three vehicles. Three vehicles have been delivered and are in-service.
- Via Mobility was initially awarded two vehicles; the award was later expanded to four vehicles. Unfortunately delays in vehicle supply chains have caused delays in the vehicle procurement for all four vehicles. All infrastructure is being installed, and the participant is actively working to find a solution for the vehicle procurement.

The Company plans to conclude this project in 2025.

Electric Car Sharing for Underserved Communities Project

The Electric Car Sharing for Underserved Communities Project offers rebates for electric vehicles, associated infrastructure, and charging stations for income qualified and/or higher-emissions communities. The Project's main objective is to study how to reduce the upfront and operational costs of car ownership and expand access to EVs in underserved communities. Car sharing provides short-term car rentals where drivers only pay for what they use, resulting in expanded and equitable access without the prohibitive costs of car ownership. The Project was designed with a local non-profit, Colorado CarShare, that was awarded Project funding to procure 25 EVs to be distributed across seven awarded sites ("participants"). EV models procured range in amenities, configuration, vehicle type, manufacturer, and battery size to accommodate different uses, terrain, and geography types.

Status Update

The Electric Car Sharing for Underserved Communities Project launched in July 2022. The Project had eleven site host applicants, resulting in the selection of seven participants based on applicants' scoring and available funding. As of June 2024, there were five active site host participants that successfully submitted the required paperwork and received rebate funding through the Project. The participants include City and County of Denver ("CCD"), Colorado Mountain College ("CMC), University of Colorado-Boulder ("CU Boulder"), Town of Breckenridge ("Breckenridge"), and Town of Frisco ("Frisco"). There is a sixth participant, Boulder Housing Partners ("BHP"), that received funding for charging equipment through the Innovation V2X and Resilience Project. Two additional site host applicants were awarded funding but did not receive rebates for charging equipment, due to their inability to participate in the project or to adhere with stated application policies.

Site host participation is closely monitored by the Company, ensuring all participants can receive support as needed. All projects are in varying stages of completion, and all site host participants have provided detailed timelines for project completion. Four site host locations are fully launched with cars available for reservation through Colorado CarShare. All sites have reported minimal issues since launch, and feedback from drivers has been positive.

The Company plans to conclude this project in 2025.

DCFC Charging + Storage Demonstration Project

The DCFC + Storage Demonstration Project was designed to support the deployment of an in front of the meter battery energy storage solution on a capacity constrained feeder supporting a high-capacity charging hub. As a part of this project, the Company would partner with a customer installing a DCFC charging hub with 0.5MW or more of charging capacity and the project battery energy storage solution would be deployed along the same feeder as the charging hub. The battery would be dispatched according to grid needs to better understand the value it can provide as a non-wires alternative, a demand management resource, and to study the interaction of these two dispatching strategies.

Status Update

The DCFC Charging + Storage Demonstration Project launched in November 2021.

The Company's distribution team completed a multi-staged approach to identify potential battery energy storage sites that could alleviate feeder-level system constraints associated with a DCFC station. The project team initially completed an analysis to identify geographic locations with capacity-constrained feeders that were forecasted to be at or near capacity and were not slated for a significant distribution upgrade within the next three years. Once those locations were identified, the project team then identified which of the respective constrained feeders had pre-existing or planned charging infrastructure of at least 0.5 MW that contributed to the feeder's peak. After the

project team identified potential locations that both had constrained feeders and 0.5 MW of preexisting or planned charging infrastructure, the project team partnered with the land acquisition team to assess potential project sites. Due to several limitations discovered during the site identification and land acquisition process, the Company has been unable to identify an appropriate site for this project to date.

While the project team has garnered substantial valuable insight through this process, the Company is not moving forward with this project into a construction phase. However, the project has produced significant learnings, specifically around siting complexity and the types of DCFC projects that may benefit from alternative solutions in feeder constrained areas. These findings can be applied to future projects brought forward by the Company.

School Bus Electrification Program

The School Bus Electrification Program works to decrease the cost barrier, provide educational support to school districts, and increase the number of electric school buses operating in Colorado. An electric school bus currently costs approximately three times that of a diesel bus (average purchase price of a new Type C electric school bus is about $395,000[54]) and requires investment in charging equipment and potential infrastructure upgrades to accommodate vehicle charging.

The Company's initial TEP directed $2.2 million in proceeds from Renewable Energy Credits and carbon offsets to fund the School Bus Electrification initiative. School districts could apply for rebates up to a maximum of $275,000 per bus, to assist with the costs incurred to procure an electric school bus and the necessary charging equipment.

Status Update

The School Bus Electrification Program launched in October 2021.

The program had a total of seven school districts applications for a total of eight electric school buses. As of December 1, 2024, the Company has delivered rebates for two buses, with six additional rebates to be delivered.

[54] World Resources Institute's Electric School Bus Initiative, All About Electric School Bus Repowers | Electric School Bus Initiative.

DEMAND-SIDE MANAGEMENT

Charging Perks

The Charging Perks Program was approved as a permanent program in the Company's 2024-2026 TEP, Proceeding No. 23A-0242E. Charging Perks is a dynamic optimization program that rewards EV drivers in Colorado when they charge during times of day that help the energy grid operate more efficiently and use more renewable energy. Every time a participating customer plugs in at home, the Company and its EV energy-service provider or the customer's automaker will work together to automatically schedule the customer's car's charging. The customer's EV will then be charged to align with the customer's charging needs with the optimal times to charge based upon grid conditions. Customers receive a $50 bill credit upon enrollment and a $150 annual incentive for continued program participation. The pilot was made available to Tesla drivers in June 2021 and was expanded to drivers of certain Plug-in Hybrid EV models from Ford, BMW, Honda[55], and General Motors in late September 2021. The pilot was expanded to Wallbox customers in Q4 of 2023.

Status Update

As of September 1, 2024, there were 1688 customers participating in the Charging Perks (dynamic optimization) Pilot program. This pilot is now a permanent program offering. The Company provides detailed updates on program participation, costs, achievement, and other learnings about its EV optimization programs in its annual TEP Report filed each October.

Renewable Battery Connect

The previous Residential Battery Demand Response Pilot, marketed as "Battery Connect," began in February 2021 and ran for one and a half years. It successfully evaluated various energy storage concepts related to residential battery use. Renewable Battery Connect, the next iteration of this product, was filed in the 2022-2025 RES Plan approved by the Colorado Commission in September 2022. Key design changes included an increased upfront incentive and a requirement for the battery to be 100% charged by an on-site solar system, qualifying it as a renewable energy resource.

Renewable Battery Connect will continue to assess the availability of batteries for demand response and demand management applications. It will also evaluate optimal dispatch strategies to reduce grid usage throughout the day and during peak periods, considering factors such as season, customer segments, and battery vendors. This assessment is

[55] Honda ended its participation in Charging Perks in 2024.

crucial for determining the expected performance of the technology, program design, and compensation levels for future participants.

The program supports residential and small commercial customers in installing energy storage systems that are 100% charged by renewable energy. The Company has dispatch control of these systems, with the ability to dispatch up to 60 times per year to support the grid. Additionally, the Company is exploring a future pay-for-performance construct through the integration of our future Distributed Energy Resource Management System (DERMS).

The program has been highly successful, with current enrollment plus applications in the pipeline exceeding the targeted 10 MW of battery storage by the end of 2024. The Company has received Commission approval pursuant to an Unopposed Motion recently filed in Proceeding No. 22A-0315EG to allow additional funding for approximately 23 MW more of dispatchable battery storage in 2025, among other items set forth in that Motion.

FLEXIBLE INTERCONNECTION

Flexible Interconnection Demonstration Settlement Commitments

As more DER has been interconnected to the distribution system, it can be challenging to interconnect further DER without trigger system upgrades. To address the challenges of integrating more DER on high penetration areas of the system, the Company is conducting two flexible interconnection demonstrations, one for large capacity (>1 MW) DER systems and one for small DER systems (<25 kW).

In October 2023, the Company presented objective and demonstration ideas to the DSP Stakeholder Technical Working Group. Based on stakeholder feedback, the Company developed two flexible interconnection demonstrations.

Small Scale DER Flexible Interconnection

For the first flexible interconnection demonstration, the Company is targeting residential solar systems (<25kW nameplate) interconnection applications that were found to need distribution upgrades, such as a service transformer or service conductor. The upgrades that can be triggered in these instances can diminish customer adoption economics. The intent of the pilot was to evaluate whether a potential grid constraint can be managed with smart inverter settings.

To identify and enroll eligible customers, the Company reviewed the interconnection queue and identified customers who met these criteria and asked them to participate. If the customer agreed to participate in the demonstration, they would utilize their smart inverter to establish automatic settings that would adjust the solar output to not exceed

distribution system constraints. In exchange, the customer did not have to pay the originally identified distribution system upgrades.

To date the Company has reached out to approximately 50 customers, and at the time of this filing, no customers have elected to participate. One barrier to customer participation appears to be the relatively low-cost, interim $300 cap that applicants now pay for such upgrades pursuant to SB 24-218. Such upgrades historically have been in the $5,000 to $15,000 range. It is important to note that the interim cost cap for upgrades established via SB 24-218 occurred after the Company had committed to conducting this pilot. The Commission may wish to explore the interaction between upgrade cost caps and flexible interconnection incentives as part of the rulemaking required to establish cost cap treatment pursuant to SB 24-218.

Large Scale DER Flexible Interconnection

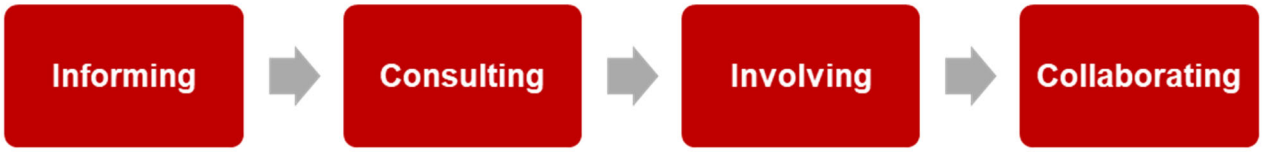
For the second flexible interconnection demonstration, the Company targeted large solar systems (>1 MW) that were found to need distribution system upgrades, had paid for those upgrades, and were in the waiting process for construction to be conducted. In these cases, the Company and developers found the value proposition in using flexible interconnection for an interim time period to get the solar system permission to operate sooner, as long as the solar system limited its output as scheduled by the Company. The Company worked with two solar developers to establish a process and draft a flexible interconnection terms and conditions template. Additionally, the Company conducted a study to estimate the potential curtailment of the solar system based on expected system conditions and solar output. Although demonstrations with developers did not move forward, the Company is proceeding with a field demonstration of flexible interconnection concepts in association with a company-owned Community Solar Garden at the Arapahoe site. This demonstration will inform future flexible interconnection offerings.

XIV. STAKEHOLDER AND COMMUNITY ENGAGEMENT AND OUTREACH

This section covers the broad topic of stakeholder and community outreach and engagement. The Company has several types of stakeholders, from state agencies and advocacy organizations to individual customers (and notably income-qualified customers and customers in DI Communities), that are part of the communities that we serve. This section addresses stakeholder commitments from the Company's 2022 Distribution System Plan, along with our anticipated efforts to broadly engage with our communities as part of the Company's plans to increase the speed and scale of grid investment through proactive planning. Robust engagement and outreach will be integral as we meet long-term system expectations and initiate foundational investments that are needed today and will prepare for the pace at which our customers adopt new technologies beyond the action period of this Plan.

The Company has been transforming its approach to engagement and outreach and we expect that to continue. Figure 73 below represents a spectrum of stakeholder engagement and, while there are certainly times when informing and consulting are useful generally, the more proactive planning of our distributions system will require significant involvement and collaboration with communities generally, including DI-Communities.

Figure 73: The Four Levels of Stakeholder Engagement



2022 DSP TECHNICAL WORKING GROUP

The Company reached an unopposed Settlement Agreement after filing its inaugural Distribution System Plan in May of 2022. As part of the Settlement Agreement, the Company agreed to establish a technical working group to discuss several technical topics including: DRMS, DER interconnection, unintentional islanding, and third-party proposals for future Distribution System Plan pilots, and hosting capacity analysis. The Company also agreed to select an independent, third-party to facilitate meetings on these topics. The Settlement agreement was approved in Decision No. R23-0080. The purpose of the technical working group was to facilitate discussion between the Company and stakeholders on the technical topics identified in the May 2022 Settlement Agreement, and the objectives of the working group were to:

- Exchange information about the technical topics identified above;
- Allow the Company and stakeholders an opportunity to share draft proposals which may be included in the Company's 2024 Distribution System Plan and to receive feedback on those proposals to inform future regulatory filings; and
- Document all proposals and feedback provided through a report created by an independent facilitator to the Colorado Public Utilities Commission.

Gridworks was selected by the Company through a competitive solicitation process to serve as a third-party facilitator. Gridworks' role was to facilitate discussion amongst the stakeholders. Gridworks did not make recommendations to the Commission but provided a report to the Commission summarizing the stakeholders' positions and proposals in the Distribution System Plan proceeding. Gridworks' main responsibilities included:

- Facilitating discussion amongst stakeholders.
- Establishing agenda items and working with stakeholders to obtain and distribute any supporting materials.
- Creating a report to the Commission on:
    - Draft proposals, as well as stakeholder feedback and positions on those proposals; and
    - The effectiveness of the facilitated stakeholder process prior to filing of the 2024 Distribution System Plan.

The technical working group met 10 times between July 2023 and April 2024 to discuss the five topics identified in the settlement. These meetings started with an opportunity for the group to review the project charter and ended with a feedback session on the draft report. The group comprised 58 individuals representing 26 organizations. All meetings

were hosted virtually and were between one and two hours, with some topics broken up into 2-part meetings. Gridworks provided a report to the Commission summarizing the stakeholders' positions and proposals in proceeding 22A-0189E. Gridworks' report is provided in Appendix 8.

STAKEHOLDER ENGAGEMENT LEADING UP TO THE 2024 DSP

More broadly, leading up to the filing of the DSP, the Company engaged with a variety of stakeholders for its new DSP Application. Stakeholder activities can take place as large group meetings or can happen in more focused small groups or as one-on-one interactions. By Commission Rule 3528(g), the Company is encouraged to convene regular, informal stakeholder meetings as well as being required to convene at least one stakeholder meeting at least 90 days prior to filing a Distribution System Plan. The Company met these requirements.

Specific to the development of this Plan and its Grid of the Future modeling, the Company facilitated several discussions throughout the summer of 2024, including with the City and County of Denver, the City and County of Boulder, and the Colorado Energy Office and our consultant Kevala. Throughout the Summer of 2024, the Company met with Boulder, Denver, and the Colorado Energy Office a total of five times in aggregate to inform them of our modeling process, seek input, and identify next steps.

The purpose of these meetings was to better understand specific community initiatives and priorities during the design phase of the Grid of the Future project and incorporate this input into the modeling process. These conversations were productive in terms of understanding priorities for these municipalities and with continued collaboration we hope to be able better synchronize our planning process with quantitative data related to community policies and goals.

In the interim, to reflect stronger incentives in Denver and Boulder, the Company instructed Kevala to develop adoption propensity weights for certain technologies (see Appendix K and Appendix L for additional information in the Kevala report provided at Appendix 1) in earlier forecast years; these weights could be updated and extended to reflect additional assumptions on a more granular basis in the future. More broadly, the Company attempted to reflect the goals of communities such as Denver and Boulder, among other drivers, in the development of its "Goal Aligned" scenario.

In terms of more general stakeholder engagement, the Company offered two broad stakeholder meetings in advance of filing this DSP. These meetings were open to recent parties to Distribution System Plan cases, and other interested stakeholders. The Company has had good participation in these meetings, including representatives from state agencies, communities, and various advocacy organizations. Table 32 below

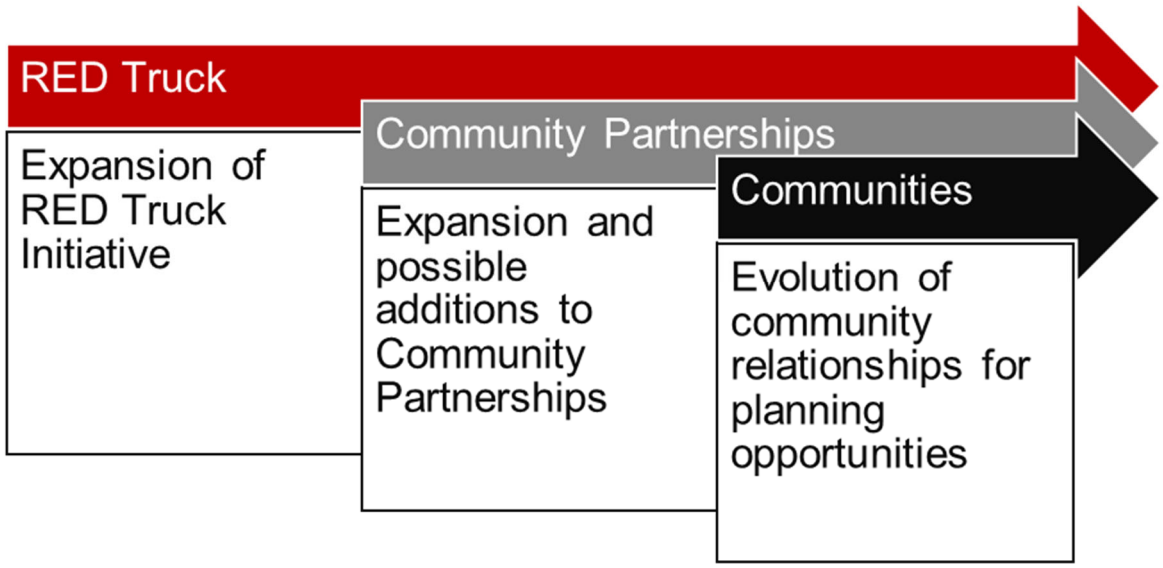
contains the two general stakeholder meeting that were held and the topics that were discussed.

Table 32: DSP and Grid of the Future Stakeholder Meetings

Meeting Date	Topics
April 15, 2024	Boulder Modeling Meeting and Update on Climate Study
July 22, 2024	Follow up to Initial Boulder Modeling Meeting
July 30, 2024	Colorado Energy Office Modeling Meeting
July 31, 2024	Follow-up from July 22 Boulder meeting
August 8, 2024	Denver CASR Modeling Meeting
August 14, 2024 (General Stakeholder Meeting)	History & Evolution of the Distribution System
	Our Approach and Vision for this DSP
	Regulatory “Sandboxes”/alternative regulatory approaches
November 11, 2024	Detailed Preview of DSP Plan with Denver
December 3, 2024 (General Stakeholder Meeting)	DSP Overview
	The Evolution of Distribution Planning
	Grid Needs Assessment
	Scenario Analysis
	GMAC Performance Screen

COLLABORATION WITH COMMUNITIES – PLANNING FOR THE FUTURE

Based on the projected outcomes from this DSP, the Company plans to significantly expand its efforts to engage with its customers and communities. This will include the expansion of current approaches, like the RED Truck initiative (described below). In addition, it will also include expanding our partnerships with key community organizations such as the Latino Community Foundation of Colorado (LCFC). The Company anticipates evolving its relationships with the communities it serves by collaborating on planning and the deployment of various types of electrification, efficiency, and DERs.



RED Truck Initiative

The RED (Resources. Education. Delivered.) initiative launched in May of 2023. RED Truck is a new, free service Public Service is offering to help community members get access to relevant energy information. The RED Truck initiative will continue to be a significant channel for the Company to actively engage with its customers and communities.

Staffed with our energy experts and equipped to connect specific customer accounts, the RED Truck travels across Public Service's service area to deliver energy savings tips and tools on the spot to communities at various events. Information distributed includes a focus on energy assistance programs, energy efficiency, clean transportation and renewable energy offerings, and other community outreach materials. The RED Truck also provides a direct route for the Company to engage and interact with customers, giving customers the opportunity to offer feedback as well as ask questions about the Company's programs, energy initiatives, and other issues of interest.

By the end of 2024, Public Service will have participated in nearly 78 events across the state. At these community-based events, the Company provides energy education, connects individuals to energy assistance, and collects feedback directly from customers. The Company estimates that it reached over 1,452 customers, with a total of over 3,918 of assistance materials distributed at these events.

Looking forward, the RED Truck will be a useful tool as distribution projects are undertaken in the various communities the Company serves, and as additional demand response and other load flexibility programs are made available to our customers. It is also part of the Company's evolving IQ/DI Community Engagement and Outreach Plans. Public Service anticipates focusing RED Truck deployment to distribution project areas where we can have meaningful engagement and impact with the community. It is also anticipated our approach will continue to be refined as we target these outreach activities to communities.

IQ/DI Community Engagement and Outreach Plan

In the fourth quarter of 2023, Public Service officially initiated a new partnership with the LCFC to implement its IQ/DI Community Engagement and Outreach Plan. Known as *Energize Together*, the program aims to create new models for Public Service to conduct authentic community engagement with historically under-resourced communities throughout Colorado. *Energize Together's* goal is to provide these communities with equitable access to support, resources, and incentives to reduce any financial burden associated with energy costs, while also facilitating access to clean energy incentives, fostering better clean energy and energy efficiency in the state. The Company anticipates utilizing this partnership to further its engagement with its customers and communities as projects are planned and implemented on its distribution system.

Planning for Critical Customers/Infrastructure

Through much of 2024 the Company has been engaged in a broader effort to identify critical customers and infrastructure. We have been working closely with our communities and customers with our Company's Community Relations and Key Accounts groups to compile these lists. From this input we are utilizing available definitions and guidelines to creating tiers of sites. While that effort is ongoing and there is not yet a single, agreed-upon definition, Public Service is comfortable that the customers treated as critical for this NWA screening process would be considered critical under any reasonable definition. This is effort is currently ongoing.

Forecasted Community Engagement and Outreach Budget

With the Company's plans to expand and evolve its relationships with its customers and communities, it is currently forecasting a five-year budget of approximately $6.8 million that is particularly focused on DI-Communities. This budget covers expansion of the RED Truck program and provides funding to our community partners to further step up engagement in DI communities. Table 33 below breaks down the forecasted budget for this activity:

Table 33: Stakeholder Engagement and Outreach Budget Forecast 2025-2029

Year	Educational / Outreach Programs & Support Materials	Staffing	RED Truck Costs	Engagement	Total
2025	$200,000	$232,000	$195,000	$170,000	$797,000
2026	$210,000	$554,000	$205,000	$190,000	$1,159,000
2027	$220,000	$817,000	$215,000	$215,000	$1,467,000
2028	$230,000	$1,100,000	$130,000	$240,000	$1,700,000
2029	$240,000	$1,100,000	$40,000	$265,000	$1,645,000
Total	**$1,100,000**	**$3,803,000**	**$785,000**	**$1,080,000**	**$6,768,000**

Educational and outreach programming will use funds designated for raising awareness and educating the public on the importance of sustainable infrastructure development. This includes hosting workshops, community meetings, and public seminars where experts can discuss project benefits, environmental impacts, and community gains. Community support materials will cover the costs for creating and distributing materials such as detailed maps, brochures, and informational guides that are crucial for effective community outreach. These materials are designed to provide clear, accessible information about project locations, objectives, and impacts to ensure transparency and foster community trust.

Staffing costs will consist of a ramp-up of employees that can plan and assist RED Truck events. The budget forecast envisions a total of eight employees being assigned to these duties by 2029 with a project manager. In addition, the RED Truck costs are comprised of fleet expansion and maintenance. This includes funding for translation services, cultural competency training for staff, and partnerships with local cultural organizations to ensure that outreach efforts are respectful and responsive to community needs.

As for community engagement costs, we forecast a budget allocated to compensate community members for their time and contributions during planning and feedback sessions. This ensures that community participation is not only encouraged but also valued and respected, making the engagement process more inclusive and equitable. For cultural accessible engagement activities, we expect those to start at $35,000 in 2025 and increasing to $75,000 by 2029.

Our engagement activities will also require the use of advanced analytics to monitor and refine outreach strategies. Funding starts at $15,000 and grows to $30,000 by 2029, reflecting an increasing reliance on data to drive decision-making and improve the

effectiveness of community interactions. This also covers the costs of developing and maintaining digital platforms that facilitate interactive engagement. These platforms serve as critical tools for reaching a broader audience and providing ongoing access to project information and updates, with the budget increasing from $80,000 in 2025 to $100,000 by 2029.

XV. PERFORMANCE-BASED FRAMEWORK

SB 24-218 provides for a performance-based framework with three components: (1) applicable interconnection timelines based on the time periods established by the Commission; (2) energization timelines, which will be applicable to the second distribution system plan filed after the effective date of SB 24-218; and (3) reasonable and cost-effective targets measured in megawatts for flexible load and demand management, which are also applicable to the second distribution system plan filed after the effective date of SB 24-218. These three components build from existing or developing Company practices, and in some elements, from Commission rules. This performance framework is intended to ensure that qualifying retail utilities meet Commission-approved performance standards that are intended to promote a positive customer experience and the efficient progress towards the State's clean energy goals, as a condition of current cost recovery of Type 2 Distribution Activities through the GMAC.[56] We propose that the performance framework be called the GMAC Performance Screen, or "GPS."

INTERCONNECTION TIMELINES

The Commission has established timing requirements for the interconnection of DERs through its Interconnection Procedures and Standards, Rules 3850 through 3859, 4 Colorado Code of Regulations ("CCR") 723-3. Through Commission Proceeding No. 23AL-0188E, Public Service has also established an Interconnection of Distributed Energy Resources policy in its electric tariff consistent with these requirements and instituted a performance incentive mechanism and refund mechanism based on whether the Company meets interconnection timelines for Level 1, Level 2, and Level 3 interconnection applications.

The performance standard established by the Commission for the timing of DER interconnections should determine the extent of the annual revenue requirement associated with Type 2 Distribution Activities that can ultimately be recovered through the GMAC for each year on a percentage basis based on the number of days late, if any, that the Company has been in executing DER interconnections over the applicable year. The Company proposes that if the average number of DER interconnection days late is zero (or if the Company is, on average, interconnecting ahead of schedule), or in other words if the Company is delivering the level of service expected for its customers, the Company should be authorized to recover 100 percent of the Type 2 Distribution Activities annual revenue requirement. If the Company, on average, is not achieving that level, this

[56] Type 2 Distribution Activities are the distribution activities that the Company undertakes pursuant to a Commission-approved DSP that the Commission finds do not benefit or advance the goals reflected in SB 24-218. See § 40-2-132.5 (7)(b)(III), C.R.S.

percentage of cost recovery should decrease in a linear fashion until 60 average interconnection days late, at which time the Company would not be permitted to have GMAC recovery of any of the annual revenue requirement for Type 2 Distribution Activities for the applicable year. By way of example, under this linear approach, the Company would only recover through the GMAC 50 percent of the annual revenue requirement associated with Type 2 Distribution Activities if it is on average 30 days late in completing DER interconnections.

The Company provides regular updates to the Commission on its performance in executing interconnections through reports filed in Commission Proceeding No. 22M-0032E.

FLEXIBLE LOAD AND DEMAND MANAGEMENT

SB 24-218 requires this DSP to include a target-setting framework measured in megawatts for flexible load and demand management ("FLDM"). which would be established through this DSP proceeding but take effect in the Company's next Distribution System Plan. Flexible load and demand management have been discussed in multiple proceedings including the Demand-Side Management/Beneficial Electrification ("DSM/BE") Plan, TEP, RES Plan, DSP, and CHP. While the Company proposes a general FLDM target-settling framework in this Plan as required by SB 24-218, the specific details and mechanics of the framework will be established through the Company's next Distribution System Plan.

The Company proposes that the target-setting framework for FLDM should set an overall MW goal based on established, Commission-approved programs that have adopted goals for demand management and/or flexible load as of the date the next Distribution System Plan is filed. The flexible load and demand management goals established in our current regulated programs are reflected in Table 34.

Table 34: FLDM Goals Reflected in Current Regulated Programs

Filing	Program	2026 MW Goal
DSM	Residential Demand Response	263
DSM	Critical Peak Pricing	68
DSM	Peak Day Partners	29
DSM	Peak Partner Rewards	53
DSM	Small Commercial Building Controls	1
DSM	Interruptible Service Option Credit	195
TEP	Electric Vehicle Critical Peak Pricing	2
TEP	Electric Vehicle Charge Optimization	5
RES	Residential Battery Demand Response	10
	Total	**626**

The Company generally recommends that quantification of FLDM achievement, demonstrated by enrollment in an applicable program, should for each program follow the procedures established in the applicable proceeding addressing that program. Moreover, the implementation of the FLDM framework and the metrics for performance evaluation can be addressed in future Distribution System Plan cycles, consistent with SB 24-218. The metrics for evaluation are a complex consideration that merit further consideration and evaluation once a general framework for FLDM consideration exists.

Each of these proceedings, with the exception of the DSP, have focused on the customer side of the load flexibility transaction and the bulk system impacts of the interventions. As discussed previously in this Plan, regulated programs to support load flexibility, which have previously been utilized primarily for the benefit of the bulk system, will evolve. For example, load flexibility with more location-specific benefits should be considered in future proceedings. Additionally, use of load flexibility resources to benefit the distribution system should also consider the impact these actions may have on the bulk electrical system as well interactions with the gas system. Evaluation of the interactions between generation, distribution, and gas systems is a new and growing area of study for the Company and all utilities. The universe of end use interventions is also likely to expand to meet the growing need for flexible load on the distribution system. Flexibility resources such as customer-sited storage, dispatchable distributed generation, flexible interconnections, dynamic fuel switching for heat pumps, as well as rates, may play a role.

Nevertheless, a GPS that utilizes a high-level metric such as what we have proposed above can be effective in evaluating the use of these resources, consistent with the statutory intent of SB 24-218. The specific metrics and values for future iterations of the performance framework can be developed through future programmatic proceedings (e.g., RES, DSM, TEP) as appropriate, and combined into a unified metric in the GPS in future Distribution System Plan proceedings.

LOAD ENERGIZATION TIMELINES

Pursuant to SB 24-218, the Company will present a performance-based framework on load energization timelines for the Commission's consideration in the Company's next Distribution System Plan proceeding. As discussed in the section above entitled Enhancing the Customer Journey, the Company is now in the process of collecting the data on its energization performance that will be needed to inform this framework.

HOW PERFORMANCE FRAMEWORKS WILL WORK TOGETHER TO INFORM GMAC RECOVERY FOR TYPE 2 DISTRIBUTION ACTIVITIES

Consistent with the timing reflected in SB 24-218, the only component of the performance framework that will be applicable to this DSP is the one addressing the Company's timing for the interconnection of DERs based on the timing requirements established in the Commission's interconnection rules and reflected in the Company's Commission-approved interconnection tariff. The Company will calculate the annual revenue requirement associated with Type 2 Distribution Activities in the same manner that it calculates the annual revenue requirement for Type 1 Distribution Activities, as described above. However, the percentage of the annual revenue requirement for the performance year associated with Type 2 Distribution Activities that the Company can ultimately recover will depend on the Company's performance under the DSP performance framework during the year, as described by Company witness Jack Ihle. Because the Company's performance on these metrics will not be known in advance of annual November 1 advice letter filings, the Company proposes to address necessary adjustments under the DSP performance framework through the GMAC April true-up process. In the forecasted rate included in the November 1 advice letter filing, the Company will assume achievement of the targets for 100 percent cost recovery for Type 2 Distribution Activities for purposes of developing estimated revenue requirements to be recovered through the GMAC. If the Company's calculated performance ends up being less than 100 percent, an adjustment would occur in the applicable year's April true-up and be included in the subsequent November filing to reduce the actual revenue requirement for Type 2 Distribution Activities.

The Company proposes to include distribution investments subject to the performance framework and subsequent screen (i.e., Type 2 investments) prospectively in the November 1 GMAC filing each year, which will subsequently be reviewed in the relevant April 1 filing once performance for the full year can be assessed. Importantly, the

Company proposes that all cumulative Type 2 distribution investments up to and including the performance year be subject to each year's performance screen.

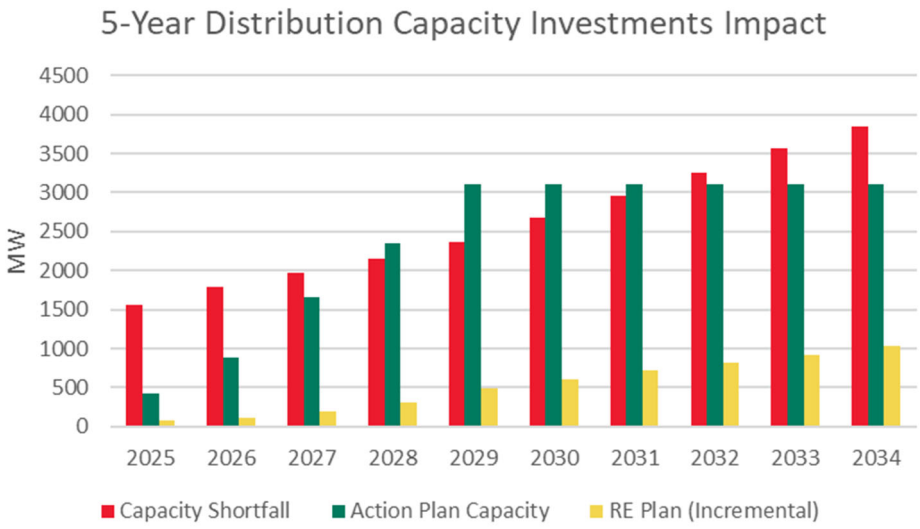
XVI. ACTION PLAN

The Company's action plan summarizes the plan detail into a near and long-term set of actions plans of the Distribution System Plan. The first five years will be focused on making necessary investments to unlock new capacity on the distribution system that will set a trajectory for the long-term achievement of state policy goals and customer preferences, the details of the investment plan can be found in the Grid Needs Assessment, Section VII of this comprehensive plan document. As the Company's modeling suggests, these capacity investments are foundational in nature given that all long-term modeling scenarios suggest a similar pathway over the next five years. These investments will be complemented by benefits and outcomes resulting from near-term investments from our Grid Modernization, Modeling and Forecasting, and Non-traditional solution initiatives described further below.

INCREMENTAL HOSTING CAPACITY UNLOCKED BY THIS PLAN

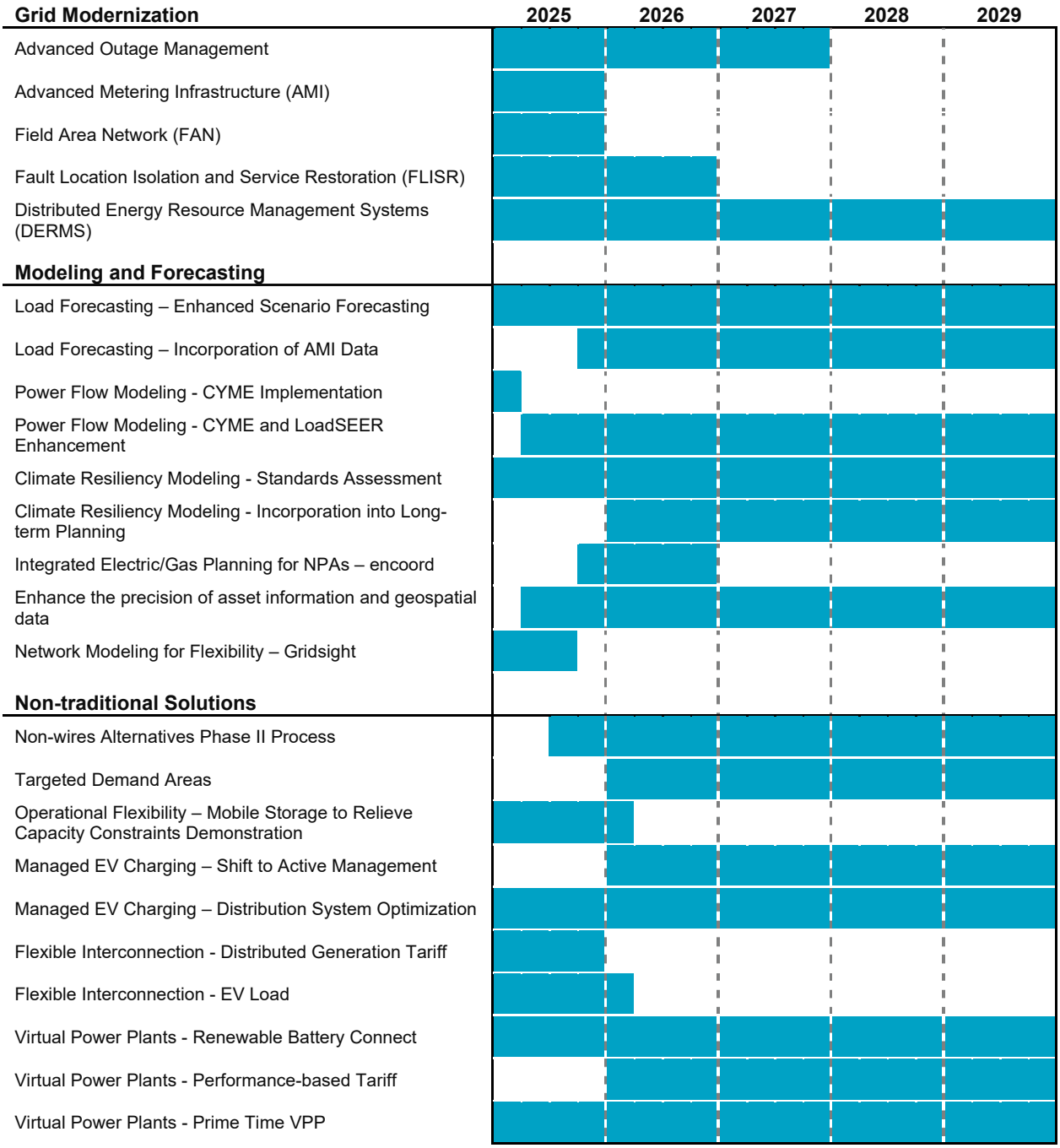
The 5-year action plan will continue to be updated each year as the Company updates the forecast and grid needs to ensure the distribution system is meeting customer's needs. Through our planned distribution system investments, we estimate an overall increase of 3,000 MW in feeder hosting capacity as illustrated by Figure 74. In this figure you can see the beginnings of our planning approach start to materialize when examining the relationship between capacity deficit and surplus. We must start first with building back base system capacity in order meet our customers' needs, and this is represented by the fact that the red, "Capacity Shortfall" bars exceed the green "Action Plan Capacity" bars in years 2025-2027. In 2028, one can see the impact of capacity investment on our system as the green bars now exceed the red. In concert with our shift to a 75% loading standard, we are positioning our planning process to build the green capacity in advance of the red demand. We expect this profile of investment versus demand to continue as we navigate the demand growth being experienced across the industry and by the Company.

Figure 74: Additional Capacity Provided on the Distribution System through the Plan



However, the action plan also brings together new capabilities through grid modernization initiatives, enhancements to our modeling and planning processes, and pursuit of non-traditional solutions as reflected in Figure 75.

Figure 75: Five-year Action Plan



Concurrently, we will complete the deployment of foundational technologies (e.g. AMI) and other grid modernization initiatives include FAN, ADMS, and the first stages of our long-term DERMS strategy which includes deploying Aggregator DERMs and a limited deployment of Grid DERMs.

NEAR-TERM GRID MODERNIZATION INITIATIVES

Many of the near-term Grid Modernization initiatives are well known to stakeholders and provide the platform for future capabilities. This Plan also includes advancement to our ADMS system as well as the first phase of our DERMS strategy (Aggregator DERMS).

Table 35: Grid Modernization Implementation Timelines

ADMS / Advanced Outage Management	The Company is currently on version 3.7 of our ADMS product. The project consists of deploying a single consolidated platform with that includes upgrading the current ADMS from version 3.7 to the newer version 3.9 version and a new outage management system. The Advanced Outage Management (AOM) project will enhance the Company's management of the distribution system by consolidating multiple software platforms into a single consolidated distribution management platform. The Company expects the AOM project to be complete in PSCo in 2027.
AMI	The Company anticipates completing deployment of AMI in 2025.
FAN	The Company anticipates completing deployment of FAN in 2025.
FLISR	The Company anticipates completing the majority of the deployment of FLISR in 2025 with some activities to be completed in 2026.
DERMS	The Company will be implementing DERMS in several phases. The aggregator DERMS will be implemented in 2025 and the grid DERMS will start with a solicitation for a consultant in early 2025 to help effectuate Grid DERMs requirements working towards a future limited, deployment.

NEAR-TERM MODELING AND FORECASTING INITIATIVES

In addition to completing the discrete grid modernization investments described above, we are also taking near-actions to improve the ways that we are modeling and planning the distribution system. Many of these capabilities will be essential for the Company to be able to execute on planning for an integrated energy system. Table 36 highlights the near-term initiatives that the Company is undertaking during the action plan period.

Table 36: Modeling and Forecasting Implementation Timelines

Load Forecasting – Scenario Forecasting	The Company incorporated forward-looking forecasts of DER adoption into our planning process through LoadSEER that model DER at a more granular spatial (i.e. premise level) and temporally (i.e. hourly). The Company engaged Kevala to run additional scenarios out to 2050. The next steps in the Company's load forecasting process will include increasing the number of internally run scenarios and development of alternative mitigation plans that correspond to these scenarios. We anticipate being able to run multiple scenarios by the time the Company is proposing to file its next Distribution System Plan.
Load Forecasting – Incorporation of AMI Data	As the Company completes the deployment of AMI through 2025, interval metering data can be used to enhance several processes including load forecasting and DER interconnection. The Company is taking foundational steps through the creation of a Universal Data Platform that will allow multiple departments in the Company to access this data as a single source of truth. While we are creating the infrastructure to achieve this, we must also build up a robust historical data set from AMI for it to be more useful. This will occur over time after the AMI deployment is completed and we have a comprehensive data set spanning multiple years.
Power Flow Modeling - CYME	Improving our power flow modeling capabilities is fundamental to consideration of both traditional and non-traditional solutions as well as the load forecasting process. The Company will complete the deployment of CYME in 2025 and then further integrate CYME with our load forecasting and engineering analysis processes.
Integrated Electric/Gas Planning – encoord	Integrated planning across the gas and electric systems is important as we consider a combination of non-traditional solutions such as non-pipeline alternatives. The Company will be working with encoord, a modeling and analytics firm to improve the efficiency of our NPA process through an integrated modeling approach that is able to link both the electric power flow and gas hydraulic modeling. We anticipate beginning this project in late 2025 when CYME has been fully implemented.
Enhancing the precision of asset information and geospatial data	The Company is undertaking an Asset Data Registry project designed to improve accuracy and complete of asset attributes for the more than 5000 attributes which are tracked in the Company's systems. The Company is taking a use case-based approach to refine this information. This project kicked off in later 2024 and will run through 2029 based on current estimates. This project is still developing, and final completion date is pending

	budget funding and we will refine the timeline as the project matures.
Network Modeling for Flexibility – Gridsight	To enable additional flexibility on the system, the Company will be working with Gridsight through 2025 to leverage AMI data to conduct more detailed hourly modeling to understand network constraints. We anticipate that this work can be used to inform visibility and communications requirements to unlock additional network flexibility related to DER integration and flexible interconnection.

Finally, the Company has several ongoing initiatives discussed in this Plan related to the deployment of non-traditional solutions such as NWAs and VPPs. As the distribution system is the backbone that connects customer DERs and non-traditional assets, we are pleased to reflect a multitude of these non-traditional solutions in the near-term of our five-year action plan.

Table 37: Non-traditional Solutions and Implementation Timelines

Non-wires alternatives	The Company has identified seven opportunities for non-wires alternatives that meet the definition of Major Distribution Grid Projects.
Operational Flexibility – Mobile Storage to Relieve Capacity Constraints	The Denver Terminal Substation is forecasting two substation bank overloads in 2026. The Company has already initiated a capacity project to relieve the overloads but will not be constructed in time due to supply chain issues. As an interim solution, the Company is installing a 1 MW/2 MWh mobile battery on an owned parcel of land along West Colfax Avenue that used to site the Company's retired 4kV Java Substation that has since been decommissioned. Once the infrastructure solution is completed, the battery can serve other needs on the grid.
Targeted Demand Areas	The Company has identified five targeted demand areas that it will be pursuing. The Company is planning to leverage existing approved budget through its 2024-2026 DSM Plan.
Managed EV Charging – Shift to Active Management	The Company is phasing out the passive "Optimize Your Charge" program and shifting more of its managed charging programs to an active load shifting approach through the Charging Perks program. This active approach to managed charging is expected to yield greater benefit to the grid.
Managed EV Charging – Distribution Optimization	The Charging Perks program today is designed to manage charging to reduce peaks on the bulk system. However, it will also be important to leverage load flexibility to mitigate local peaks on the distribution system. The Company issued an RFP for the next iteration of its EV managed charging in Q4 of this year. One of the new capabilities we sought in this platform is the ability to establish an objective function for managed charging schedules that seeks to reduce local grid impacts – effectively enabling the use of managed

	charging to support specific needs and locations on the distribution system.
Flexible Interconnection – Distributed Generation	Building upon the learnings from the Flexible Interconnection demonstrations the Company conducted since the last Distribution System Plan, the Company will be filing a flexible interconnection tariff in 2025.
Flexible Interconnection – EV Load	The Company is exploring the use of Flexible Interconnection for certain types of EV load as one of the use cases for a Grid DERMS deployment. We anticipate further developing the requirements for this use case in early 2025.
Virtual Power Plants – Renewable Battery Connect and VPP Tariff	The Company's existing VPP program, Renewable Battery Connect, has been extremely successful with approximately 10 MW of behind-the-meter batteries enrolled in the program and another 13 MW in the intersection queue. The Company expects to further expand the use of battery-based VPP programs by developing a performance-based compensation tariff that will be filed in February of 2025. The batteries enrolled in these programs today and in the future will be managed through the Company's Aggregator DERMS deployment.
Virtual Power Plants – Prime Time VPP	The Company was one of three utilities selected by the Department of Energy in 2024 under the Distributed Energy Systems funding opportunity for its joint VPP proposal with Boulder, NREL, and CU Boulder. The focus of the project will be to evolve our VPP strategy to facilitate the inclusion of DER solutions into utility processes, organization structure, and information technology and operational technology infrastructure focused on the distribution system. While the award is being finalized, the project is expected to run for eight years.

PILOTS AND PROGRAMS

The Company is not bringing forward and new pilots or programs under this Plan. However, we have highlighted a few projects (e.g. encoord and Gridsight), which reflect ways that we are embedding innovation into our planning and modeling processes.

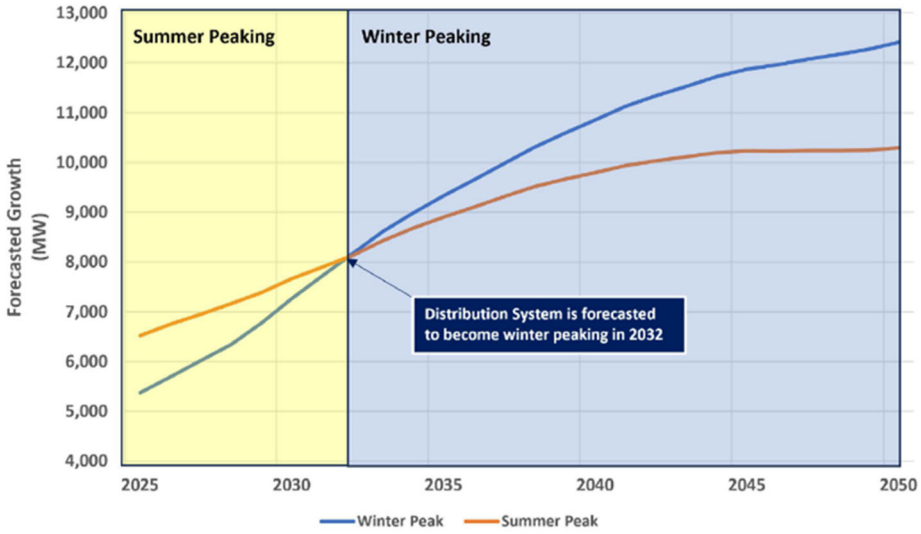
INTERACTION OF PLANNED OR PROPOSED INVESTMENTS WITH OTHER UTILITY PROGRAMS

This Plan reflects a concerted effort by the Company to unify our assumptions and efforts across multiple proceedings that impact the future of the distribution system. For example, as described in the load forecasting section of the Plan, the Company's evolved forecasting process now reflects the forward-looking adoption of DERs consistent with other proceeding such as Clean Heat. Additionally, the Plan discusses some of the ways that we are expanding our solutions to solving grid needs by evolving certain programs to target needs on the local distribution grid.

LONG-TERM LOAD GROWTH ASSUMPTIONS

As discussed in this Plan, the distribution system budgeting process covers a five-year horizon. In Section VI, we provided our forecast of load growth that corresponds to the capacity investments brought forth in this Plan. Based on our Base Forecast we estimate that the distribution system will need to serve approximately 2x the demand that it does today – and it will need to serve that load during the coldest months of the year as the system shifts to winter peaking due to electrification of heating as indicated by Figure 76.

Figure 76: Coincident Forecasted Distribution System Peak Demand



In addition to our Base Forecast, the modeling Commissioned by Kevala shows that under more aggressive adoption scenarios that meet state goals, demand could grow by 3-4x by 2050. As we implement our action plan, it will be critical to calibrate these projections against actual customer technology adoption trends and shifts in energy and demand that these technologies correspond to.

XVII. CONCLUSION

Public Service is pleased to present its second DSP, which represents a fundamental shift in the way we plan our distribution system and lays the groundwork for achieving our long-term Grid of the Future Vision. The Company looks forward to engaging with stakeholders and the Commission over the course of this proceeding.



xcelenergy.com | © 2024 Xcel Energy Inc. | Xcel Energy is a registered trademark of Xcel Energy Inc. | 24-11-412

Public Appendix 1 - Kevala Electrification Impact Model Report

Scenario Analysis of Distribution Grid Capacity Needs in Colorado

Prepared for: Public Service Company of Colorado

Submitted by:

Kevala, Inc.
550 California Street, Suite 650
San Francisco, CA 94133

December 16, 2024

Table of Contents

Executive Summary **1**
Background and Context 2
Study Approach 3
Results and Conclusions 4
1. Introduction **7**
1.1 Context and Objectives 7
1.2 Report Outline 8
2. Study Approach **10**
2.1 Electrification Impacts Model Overview 10
2.1.1 Prepare and Ingest Data 12
2.1.2 Simulate Base Load and Forecast Customer Load Growth 12
2.1.3 Create Connectivity Models 13
2.1.4 Estimate Demand Modifiers 13
2.1.5 Develop Net Loads and Determine Grid Capacity Needs 14
2.1.6 Quantify Costs of Capacity Needs 14
2.2 Scenario Analysis 14
3. Results, Analysis, and Key Findings **17**
3.1 Results 17
3.2 Analysis and Key Findings 20
4. Conclusions and Areas of Future Study **27**
Appendix A. Data Ingestion and Mapping **29**
A.1 Study Data 29
A.2 Data Ingestion 30
A.3 Data Mapping 31
Appendix B. Base Load and Customer Load Growth Methodology and Additional Results **32**
B.1 Approach 32
B.2 Analysis and Results 37
Appendix C. Net Load Modeling Methodology and Additional Results **39**
C.1 Approach 39
C.2 Analysis and Results 39
Appendix D. Grid Capacity Needs Modeling Overview and Additional Results **49**
D.1 Approach 49
D.2 Analysis and Results 51
Appendix E. Upgrade Cost Estimates Modeling Methodology and Additional Results **58**
E.1 Approach 58

E.2 Analysis and Results 60
Appendix F. Solar PV Modeling Methodology and Additional Results 69
F.1 Approach 69
F.2 Analysis and Results 74
Appendix G. Residential Battery Energy Storage System Modeling Methodology and Additional Results 95
G.1 Approach 95
G.2 Analysis and Results 97
Appendix H. Energy Efficiency Modeling Methodology and Additional Results 105
H.1 Approach 105
H.2 Analysis and Results 109
Appendix I. Demand Response Modeling Methodology and Additional Results 117
I.1 Approach 117
I.2 Analysis and Results 119
Appendix J. EV and EVSE Modeling Methodology and Additional Results 129
J.1 Approach 129
J.2 EV Adoption Pipeline 129
J.3 EVSE Adoption Pipeline 133
J.4 Analysis and Results 137
Appendix K. Heat Pump Water Heating Modeling Methodology and Additional Results 160
K.1 Approach 160
K.2 Analysis and Results 163
Appendix L. All-Electric Heat Pump Heating, Ventilation, and Air Conditioning Modeling Methodology and Additional Results 172
L.1 Approach 172
L.2 Analysis and Results 176

List of Tables

Table 1: Noncoincident peak net loads with losses (kW) for five substations by scenario: 2024-2050 (Source: Kevala) 18

Table E-1: Unit costs for feeders by line type and urbanization category (Sources: Kevala, PSCo) 59
Table E-2: Unit costs for substations and substation transformer banks by urbanization category (Sources: Kevala, PSCo) 59
Table E-3: Grand total (in nominal dollars) of all assets across all years by scenario: 2024-2050 (Source: Kevala) 60

List of Figures

Figure ES-1: Cumulative nominal costs by year and scenario for all asset types: 2024-2050 (Source: Kevala) 2
Figure ES-2: New assets (without service transformers) by scenario: 2024-2050 (Source: Kevala)..... 4
Figure ES-3: System net load with calculated losses (GW) by scenario: 2024-2050 (Source: Kevala) 5

Figure 1: Kevala's Electrification Impacts Model tailored to this study (Source: Kevala) 12
Figure 2: System coincident peak net load with calculated losses (GW) by scenario: 2024-2050 (Source: Kevala) 17
Figure 3: New assets (without service transformers) by scenario: 2024-2050 (Source: Kevala)..... 19
Figure 4: Cumulative nominal costs by year and scenario for all asset types: 2024-2050 (Source: Kevala) 20
Figure 5: Percentage of system net load peak days by season and scenario: 2025-2050 (Source: Kevala) 21
Figure 6: CSG system adoption across PSCo's service territory, Scenario 2 (Policy Aligned) vs. Scenario 3 (Calibration): 2024-2050 (Source: Kevala)..... 23
Figure 7: System-level net loads for the Goal Aligned scenarios (2, 2a, and 2b): 2024-2050 (Source: Kevala) 25
Figure 8: Count of new feeders required for the top five substations by 2050 (Source: Kevala) 26
Figure 9: Count of new transformer banks required for the top five substations by 2050 (Source: Kevala) 26

Figure A-1: Number of PSCo's grid assets mapped for the study (Source: Kevala) 31
Figure B-1: Base load and load growth modeling approach (Source: Kevala) 32
Figure B-2: Percent load growth used in Kevala's base load forecast: 2025-2050 (Sources: PSCo, Kevala) 35
Figure B-3: Minimum, average, and maximum temperatures (°F) between 2018 and 2043 by month (Source: Kevala analysis of NREL Sup3rCC data) 36
Figure B-4: HDD and CDD comparisons (using the cumulative delta) between 2018 and 2043 weather data (Source: Kevala)..... 36
Figure B-5: Base load system peak demand (GW) and cumulative energy (TWh), 2024-2050 (Source: Kevala) 37
Figure B-6: Base load shape (GWh) on system peak day by season: 2025-2050 (Source: Kevala)..... 38
Figure C-1: Grid infrastructure connectivity diagram of substations, substation transformer bank groups, substation transformer banks, feeders, and service transformers that distribute electric power to premises via the distribution grid (Source: Kevala)..... 39
Figure C-2: Percentage of system net load peak days by season and scenario: 2025-2050 (Source: Kevala) 40
Figure C-3: Hourly base (light orange) and net load (dark orange) curves for the distribution system (GW): 2024-2050 (Source: Kevala) 41
Figure C-4: DER contribution to system peak day, peak hour load (GW) by scenario and year: 2025-2050 (Source: Kevala)..... 42
Figure C-5: Total peak system day load and DER impacts (GW) by year, Scenario 1, Policy Aligned: 2025-2050 (Source: Kevala)..... 43

Figure C-6: Total peak system day load and DER impacts (GW) by year, Scenario 2, Goal Aligned: 2025-2050 (Source: Kevala) 44
Figure C-7: Total peak system day load and DER impacts (GW) by year, Scenario 2a, Goal Aligned, Mitigation A (50%): 2025-2050 (Source: Kevala) 45
Figure C-8: Total peak system day load and DER impacts (GW) by year, Scenario 2b, Goal Aligned, Mitigation B (100%): 2025-2050 (Source: Kevala) 46
Figure C-9: Total peak system day load and DER impacts (GW) by year, Scenario 3, Calibration: 2025-2050 (Source: Kevala) 47
Figure C-10: Total peak system day load and DER impacts (GW) by year, Scenario 4, Adoption Trajectory: 2025-2050 (Source: Kevala) 48
Figure D-1: Capacity upgrade cost calculation method at different grid asset levels (Source: Kevala) .. 51
Figure D-2: New assets by type, scenario, and year: 2024-2050 (Source: Kevala) 52
Figure D-3: Number of new assets by scenario, service transformers (left) and all other assets (right): 2024-2050 (Source: Kevala) 54
Figure E-1: Pyramid showing the relationship between existing grid assets (Source: Kevala) 58
Figure E-2: Cumulative nominal costs (using 2.5% inflationary factor) by year by scenario for all asset types, 2024-2050 (Source: Kevala) 61
Figure E-3: Upgrades counts and costs (2.5% per year inflation) with (left) and without (right) service transformers by scenario and asset type: 2024-2050 (Source: Kevala) 62
Figure E-4: Upgrades counts and costs ($2024) with (left) and without (right) service transformers by scenario and asset type: 2024-2050 (Source: Kevala) 65
Figure F-1: Flow diagram of solar PV modeling (Source: Kevala) 69
Figure F-2: PV target adoptions (MW) by class, scenario, and year: 2024-2050 (Sources: PSCo, Kevala) 73
Figure F-3: Comparison of PV target adoptions (MW) by class, scenario, and year: 2024-2050 (Sources: PSCo, Kevala) 73
Figure F-4: Cumulative PV target adoptions (MW) by class, scenario, and year: 2024-2050 (Sources: PSCo, Kevala) 73
Figure F-5: Incremental and cumulative BTM PV adoptions by class, scenario, and year: 2024-2050 (Source: Kevala) 74
Figure F-6: Box and whisker plot overview (Source: Kevala) 76
Figure F-7: Distribution of residential BTM PV adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala) 77
Figure F-8: Cumulative BTM PV capacity (GW DC) by class, scenario, and year: 2024-2050 (Source: Kevala) 78
Figure F-9: BTM PV average load shape (kWh) by scenario and year: 2025-2050 (Source: Kevala) 79
Figure F-10: BTM PV system adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 80
Figure F-11: Distribution of BTM PV at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 82
Figure F-12: Distribution of BTM PV at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 83
Figure F-13: Cumulative contribution to system peak of BTM PV (MWh) by year and scenario: 2025-2050 (Source: Kevala) 84

Figure F-14: Distribution of the size of BTM residential PV systems (kW DC) by year and scenario: 2025-2050 (Source: Kevala) 85
Figure F-15: Distribution of the size of BTM commercial PV systems (kW DC) by year and scenario: 2025-2050 (Source: Kevala) 86
Figure F-16: Incremental and cumulative CSG adoptions by year and scenario: 2024-2050 (Source: Kevala) 87
Figure F-17: Distribution of CSG adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala) 88
Figure F-18: Cumulative CSG capacity (kW DC) by scenario and year: 2024-2050 (Source: Kevala) 89
Figure F-19: CSG average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala) 90
Figure F-20: CSG system adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 91
Figure F-21: Distribution of CSG at the system peak (kW) by year and scenario: 2025-2050 92
Figure F-22: Distribution of CSG at the feeder peak (kW) by year and scenario: 2025-2050 93
Figure F-23: Cumulative energy (GWh) from CSG by year and scenario: 2025-2050 (Source: Kevala) ... 94
Figure G-1: Flow diagram of BTM residential BESS modeling (Source: Kevala) 95
Figure G-2: Incremental and cumulative BESS target adoptions (MWh) by scenario and year: 2024-2050 (Sources: PSCo, Kevala) 97
Figure G-3: Incremental and cumulative BESS adoptions by scenario and year: 2024-2050 (Source: Kevala) 98
Figure G-4: Distribution of BESS adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala) 99
Figure G-5: Residential BESS average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala) 100
Figure G-6: BESS adoption across PSCo's service territory, Scenario 2 (Policy Aligned): 2025-2045 (Source: Kevala) 101
Figure G-7: Distribution of residential BESS at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 102
Figure G-8: Distribution of residential BESS at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 103
Figure G-9: Cumulative energy (GWh) from residential BESS by year and scenario: 2025-2050 (Source: Kevala) 104
Figure H-1: EE modeling approach (Source: Kevala) 105
Figure H-2: Distribution of energy savings (Source: Kevala proprietary database) 106
Figure H-3: Cumulative EE targets (MW) by customer sector and scenario: 2024-2050 (Sources: PSCo, Kevala) 107
Figure H-4: Incremental EE targets (MW) by customer sector and scenario: 2024-2050 (Sources: PSCo, Kevala) 108
Figure H-5: EE savings scalers by year and scenario (% of EE load) (Source: Kevala) 109
Figure H-6: Cumulative EE energy savings by customer sector and scenario (kWh): 2024-2050 (Source: Kevala) 110
Figure H-7: Distribution of EE adoptions per feeder by year and scenario: 2024-2050 (Source: Kevala) 111
Figure H-8: EE average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala) 112

Figure H-9: EE adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 (Source: Kevala)..... 113
Figure H-10: Distribution of EE at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 114
Figure H-11: Distribution of EE at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 115
Figure H-12: Cumulative energy savings (kW) from EE by year and scenario: 2025-2050 (Source: Kevala) 115
Figure I-1: Flow diagram of DR modeling (Source: Kevala) 117
Figure I-2: Incremental and cumulative DR targets (MW) by scenario: 2024-2050 (Sources: PSCo, Kevala) 118
Figure I-3: Incremental and cumulative DR adoptions by scenario and year: 2024-2050 (Source: Kevala) 120
Figure I-4: Distribution of DR adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)121
Figure I-5: DR average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala) 122
Figure I-6: DR adoption across PSCo's service territory, Scenario 2 (Policy Aligned): 2025-2045 (Source: Kevala) 123
Figure I-7: Distribution of DR at the system peak (kW) by year and scenario, 2025-2050 (Source: Kevala) 125
Figure I-8: Distribution of DR at the feeder peak (kW) by year and scenario, 2025-2050 (Source: Kevala) 126
Figure I-9: Cumulative energy reductions (GWh) from DR by year and scenario: 2025-2050 (Source: Kevala) 127
Figure I-10: Percentage of feeders peaking coincidently with system peak by scenario (Source: Kevala) 127
Figure J-1: Overview of EV/EVSE modeling approach (Source: Kevala) 129
Figure J-2: EV targets (vehicles) by duty, year, and scenario (Sources: PSCo, Kevala) 130
Figure J-3: Personal EV targets (vehicles) by scenario, 2024-2050 (Sources: PSCo, Kevala)..... 131
Figure J-4: Fleet targets (vehicles) by scenario, 2024-2050 (Sources: PSCo, Kevala)..... 132
Figure J-5: Annual PWC EVSE targets (plug counts) by forecast year (Source: Kevala) 134
Figure J-6: Temperature range curve (Source: Geotab) 136
Figure J-7: Incremental and cumulative personal EVSE adoptions by scenario and year: 2024-2050 (Source: Kevala)..... 138
Figure J-8: Distribution of personal EVSE adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)..... 139
Figure J-9: Personal EVSE average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala) 140
Figure J-10: Personal EVSE adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 (Source: Kevala) 141
Figure J-11: Distribution of personal EVSE load at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala)..... 143
Figure J-12: Distribution of personal EVSE load at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala)..... 144
Figure J-13: Cumulative energy (GWh) from personal EVSE by year and scenario: 2025-2050 (Source: Kevala) 145

Figure J-14: Incremental and cumulative fleet adoptions by scenario and year: 2024-2050 (Source: Kevala) 145
Figure J-15: Distribution of fleet EVSE adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala) 146
Figure J-16: Fleet average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala) 147
Figure J-17: Fleet adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 148
Figure J-18: Distribution of fleet EVSE at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 150
Figure J-19: Distribution of fleet EVSE at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 151
Figure J-20: Cumulative energy (GWh) from fleet EVSE by year and scenario: 2025-2050 (Source: Kevala) 152
Figure J-21: Incremental and cumulative PWC adoptions by scenario and year: 2024-2050 (Source: Kevala) 152
Figure J-22: Distribution of PWC EVSE adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala) 153
Figure J-23: PWC EVSE average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala) 154
Figure J-24: PWC adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 (Source: Kevala) 155
Figure J-25: Distribution of PWC EVSE load at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 157
Figure J-26: Distribution of PWC EVSE load at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 158
Figure J-27: Cumulative energy (GWh) from fleet EVSE by year and scenario: 2025-2050 (Source: Kevala) 159
Figure K-1: Flow diagram of HPWH modeling (Source: Kevala) 160
Figure K-2: Annual HPWH target adoptions by class, scenario, and year: 2024-2050 (Sources: PSCo, Kevala) 162
Figure K-3: HPWH adoptions by class, scenario, and year: 2024-2050 (Source: Kevala) 163
Figure K-4: Distribution of residential HWPH adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala) 165
Figure K-5: Distribution of commercial HWPH adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala) 166
Figure K-6: HPWH average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala) 167
Figure K-7: HPWH adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 (Source: Kevala) 168
Figure K-8: Distribution of HPWH at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 169
Figure K-9: Distribution of HPWH at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 170
Figure K-10: Cumulative energy (GWh) from HPWH by year and scenario: 2025-2050 (Source: Kevala) 170
Figure L-1: Flow diagram of HP HVAC modeling (Source: Kevala) 172

Figure L-2: Annual HP HVAC target adoptions by class, scenario, and year: 2024-2050 (Sources: PSCo, Kevala) 174
Figure L-3: Annual HP HVAC adoptions by class, scenario, and year: 2024-2050 (Source: Kevala) 176
Figure L-4: Distribution of residential HP HVAC adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala) 177
Figure L-5: Distribution of commercial HP HVAC adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala) 178
Figure L-6: HP HVAC average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala)... 179
Figure L-7: HP HVAC adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 (Source: Kevala)..... 180
Figure L-8: Distribution of HP HVAC at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 181
Figure L-9: Distribution of HP HVAC at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala) 182
Figure L-10: Cumulative energy (GWh) from HP HVAC by year and scenario: 2025-2050 (Source: Kevala) 183

Acronyms and Definitions

8760: Generally refers to the number of hours in a typical (non-leap) year. Kevala describes an annual hourly energy profile as an 8760 curve.

Adoption model: A model that predicts the consumers that will be adopting a new technology. The model considers multiple variables that can reliably predict the consumer's ability and willingness to adopt a new technology such as the characteristics of early adopters, factors that drive market potential, and historical adoption rates.

Adoption propensity score: One of the outputs from the adoption model. It is a measure of a customer's likelihood to adopt relative to all other customers. Customers with higher adoption propensity scores are more likely to adopt during the adoption model simulation.

AMI: Advanced metering infrastructure

Base load: Load prior to the incremental adoption of distributed energy resources (DERs) but that includes most existing DERs as represented in Public Service Company of Colorado's billing data. This study used simulated AMI data and a year-over-year load growth factor to develop the base load.

Battery electric vehicle (BEV): Also known as an all-electric vehicle, BEVs use energy that is stored in rechargeable battery packs. BEVs sustain power through the batteries and must be plugged into an external electricity source to recharge.

Behind-the-meter (BTM): BTM refers to customer-sited DERs such as solar PV or battery storage that are connected to the distribution system on the customer's side of the utility's service meter.

BESS: Battery energy storage system

Bottom-up study: A bottom-up method forecasts the generation and load impact from DERs based on adoption models that are run at a lower level of resolution—in this case at the premise level—and aggregated up to determine the impact at higher aggregation levels such as feeders, substation transformer banks, substations, or an entire service territory.

Box and whiskers plot/chart: This chart type shows the distribution of data into quartiles, highlighting the mean and outliers. The box may have lines extending vertically called whiskers. The box represents the range of values between the upper (Q3) and lower (Q1) quartiles, and is often referred to as the interquartile range (IQR), which is calculated as Q3 minus Q1. The IQR illustrates the range of the middle 50% of the data. The whiskers show the additional range of value, with the caps being the minimum and maximum value excluding outliers. The dots

represent outliers, defined as values greater or less than 1.5 times the IQR. The line in each block denotes the median, the "x" is the mean, and the box designates the range of the lower and upper quartiles.

C&I: Commercial and industrial

CAGR: Compound annual growth rate

CDD: Cooling degree day

Census block: Statistical area bounded by visible features, such as streets, roads, streams, and railroad tracks, and by non-visible boundaries, such as selected property lines and city, township, school district, and county limits and short line-of-sight extensions of streets and roads.[1]

Census block group: Statistical division of a census tract that generally contains between 600 and 3,000 people. A block group consists of clusters of blocks within the same census tract that have the same first digit of their four-digit census block number.[2]

Census tract: Small, relatively permanent statistical subdivision of a county or statistically equivalent entity. Census tracts generally have a population size between 1,200 and 8,000 people, with an optimum size of 4,000 people. A census tract usually covers a contiguous area, but the spatial size varies widely depending on the density of settlement.[3]

Coincident peak load: The maximum energy use in an hour compared to all other hours in the year for a collection of loads, such as premises, feeders, or an entire service area. For example, a system coincident peak is the peak of the system for all customers in that system.

CSG: Community solar garden

DC: Direct current

Distributed energy resources (DERs): Includes distributed renewable generation resources, energy efficiency measures, energy storage devices, electric vehicles (EVs) and electric vehicle service equipment (EVSE), time-variant and dynamic rates, solar generation, flexible load management technologies, and demand response technologies. Most DERs are connected to the

[1] United States Census Bureau, "Glossary – Block," Surveys and Programs, Geography Program, April 11, 2022, https://www.census.gov/programs-surveys/geography/about/glossary.html#par_textimage_5
[2] United States Census Bureau, "Glossary – Block Group," Surveys and Programs, Geography Program, April 11, 2022, https://www.census.gov/programs-surveys/geography/about/glossary.html#par_textimage_4
[3] United States Census Bureau, "Glossary – Census Tract," Surveys and Programs, Geography Program, April 11, 2022, https://www.census.gov/programs-surveys/geography/about/glossary.html#par_textimage_13

distribution grid behind the customer's electric meter, and some are connected in front of the customer's electric meter.

Demand modifier: Refers to the expected hourly behavior from DERs that changes the customer's overall energy use pattern.

Demand response (DR): Refers to any change in net electricity demand made by the customer in response to an economic incentive or grid signal to reduce, increase, or shift net load relative to what the net load would have been absent the signal. The change could be temporary or recurring. Additional DR-specific definitions:

- **Event:** Set of contiguous hours in which participants will curtail demand.
- **Adopter:** Premise that will participate in DR.
- **Participant:** Customer that is actively curtailing demand in an ongoing DR event.
- **Curtailable load:** Includes base load, energy efficiency (EE), BESS, heat pump water heating (HPWH), heat pump heating, ventilation, and air conditioning (HP HVAC), personal EVSE, and fleet EVSE.

DSP: Distribution System Plan

EE: Energy efficiency

EIM: Electrification Impacts Model

Electric vehicle service equipment (EVSE): The equipment that interconnects the electricity grid at a site to an EV. Sometimes used more broadly to mean charging station, whether alternating current or direct current but not including other BTM charging-related infrastructure. EVSE equipment is classified as:

- **Level 1 (L1):** 1.9 kW
- **Level 2 (L2):**
    - Personal: 7.2 kW
    - Fleet: 19 kW
    - Public and workplace: 6.6 kW
- **Direct current fast charging (DCFC):**
    - Fleet: 50 kW
    - Public and corridor light-duty vehicles: 90 kW
    - Public and corridor medium- and heavy-duty vehicles: 200 kW

Fleet EV: Fleet EVs are zero-emission vehicles owned by or registered to an entity (not an individual) and are used for business-related purposes. Fleet EVs can be light duty (LD), medium

duty (MD), or heavy duty (HD) EVs. In the case of MD and HD fleets, EVs can only have BEV powertrains and can be one of 10 different vehicle classes/types with their corresponding driving and charging schedules.

GIS: Geographic information system

Grid topology: A representation of the physical grid that shows the connectivity among customer meters, premises, service transformers, feeders, substation transformer banks, and substations.

Gross vehicle weight rating (GVWR): The gross vehicle weight rating of a vehicle is the maximum allowable weight of the fully loaded vehicle (including passengers and cargo), as rated by the automobile manufacturer.

HDD: Heating degree day

HP HVAC: Heat pump heating, ventilation, and air conditioning

HPWH: Heat pump water heating

kW: Kilowatt

kWh: Kilowatt-hour

LBNL: Lawrence Berkeley National Laboratory

MVA: Megavolt-ampere

MW: Megawatt

MWh: Megawatt-hour

NAICS: North American Industry Classification System

Net load: The expected premise-level energy use served by a utility or, in the case of reverse flow, the level of energy the customer is exporting to the grid and the utility is expected to accept and distribute. It is the sum of the base load plus or minus the demand-modifying behaviors from DERs.

Nominal cost: For this study, costs include a 2.5% inflation increase per year after 2024.

Noncoincident peak load: The maximum energy use of customers, groups of customers, or grid assets; it does not necessarily coincide with the hour of the coincident peak. For example, a customer's peak load is considered noncoincident as it may differ from the system coincident

peak. Similarly, a feeder coincident peak, or the peak on that feeder, may be noncoincident with the system peak.

NREL: National Renewable Energy Laboratory

NSRDB: National Solar Radiation Database

Peak load: The maximum energy use in an hour compared to all other hours in the year. Peak can be used synonymously with coincident peak, which is the maximum energy use in an hour for a collective group of customers. For example, a system coincident peak is the peak of the system for all customers in that system. Similarly, feeder peak is the peak load for all load connected to that feeder. The individual peaks of customers may differ from the coincident peak and are referred to as noncoincident peaks.

Plug-in hybrid electric vehicle (PHEV): Vehicles powered by an internal combustion engine and an electric motor that uses energy stored in a battery. The vehicle can be plugged into an electric power source to charge the battery. Some can travel nearly 100 miles on electricity alone, and all can operate solely on gasoline (like a conventional hybrid vehicle).

Premise: Contiguous geographic area used by a utility to track billing and usage. It contains up to six meters and should have an address assigned to it.

PSCo: Public Service Company of Colorado

PV: Photovoltaic

PWC: Public, workplace, and corridor charging

SCADA: Supervisory control and data acquisition

Seed value: Initial value in a stochastic process. Using the same seed value will always result in the same outcome, while a different seed value will result in a different outcome.

Top-down allocation: A method for providing a transmission system-level aggregate load and DER forecast that disaggregates the load and DER forecast to distribution circuits based on utility data for the circuit (e.g., load, energy, or number of customers) or statistical propensity models.

TWh: Terawatt-hour

U.S.: United States

Vehicle duties: A vehicle duty refers to the three duty types that the U.S. Federal Highway Administration uses to categorize vehicles by gross vehicle weight rating (GVWR). The duty types are:

- Light duty: <10,000 GVWR
- Medium duty: 10,001-26,000 GVWR
- Heavy duty: >26,001 GVWR

VIO: Vehicles in operation

VMT: Vehicle miles traveled

Executive Summary

Kevala, Inc. (Kevala) conducted a Colorado-specific study using its Electrification Impacts Model (EIM) for Public Service Company of Colorado (PSCo). This geographically and temporally granular study was designed to identify potential electric distribution grid constraints and future capacity needs under multiple distributed energy resource (DER) adoption scenarios in order to affordably and reliably support the state's beneficial and transportation electrification and decarbonization goals.[4] This study complements recent enhancements to PSCo's internal distribution system load forecasting and planning processes. Taken together, the Kevala analysis and PSCo's updated planning processes reflect the next stage in PSCo's evolution of grid analytics.

Recognizing that customer adoption of DERs may occur on different trajectories, PSCo worked with Kevala to define several scenarios that reflect various degrees of attaining binding state policies and state policy goals. Kevala modeled the following scenarios:[5]

1. A **Policy Aligned** scenario (consistent with existing binding state and local mandates)
2. A **Goal Aligned** scenario (consistent with non-binding state and local electrification and decarbonization goals)
3. A **Calibration** case (based on PSCo's current Distribution System Plan (DSP) forecasting approach)
4. An **Adoption Trajectory-Informed** scenario

In addition to the above scenarios, Kevala developed load flexibility sensitivities (i.e., managed EV charging) with PSCo that were applied to the Goal Aligned scenario, which reflects the highest levels of DER adoption. These sensitivities were developed and analyzed to better understand the potential for infrastructure and cost savings associated with enhanced load management. In total,

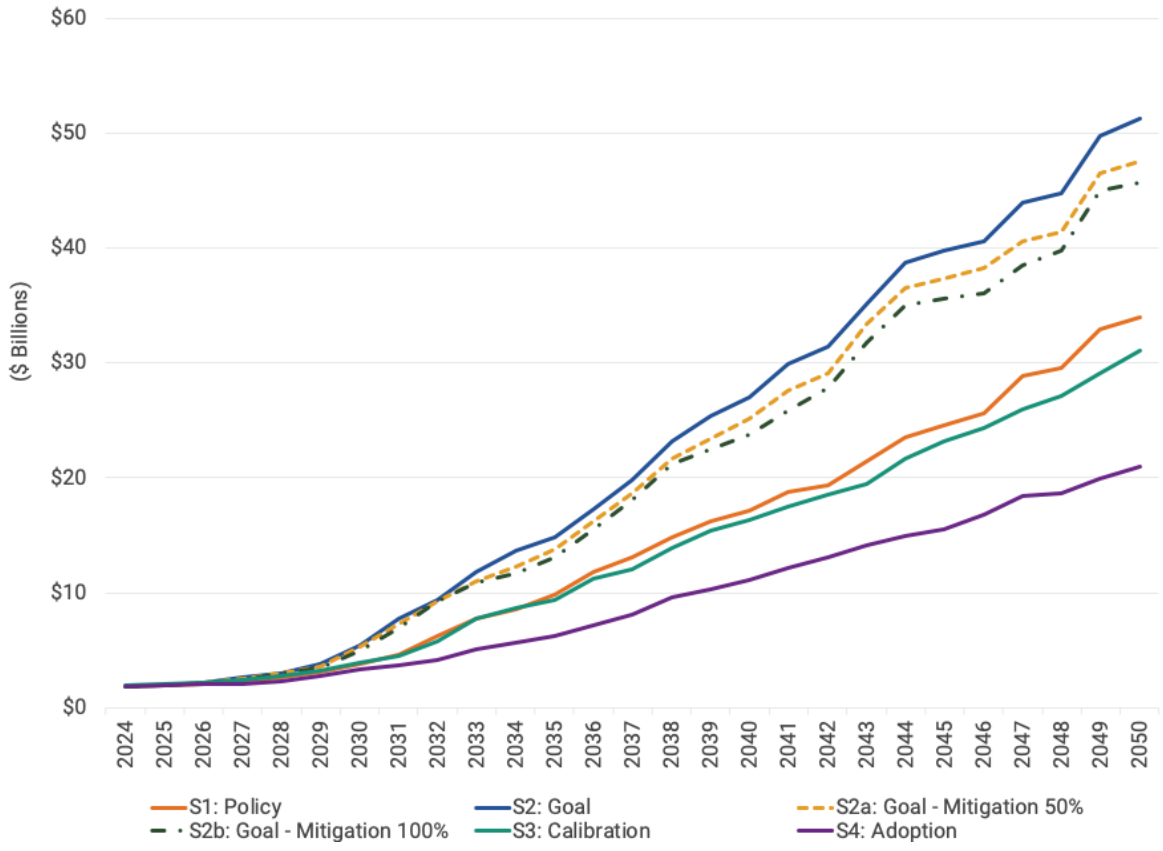
[4] Kevala has conducted the following studies using similar bottom-up approaches:
Kevala, Inc., *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates*, prepared for the California Public Utilities Commission, Energy Division for Proceeding R.21-06-017 (Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future), May 9, 2023, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF
Kevala, Inc., *Appendix Q: Electrification Impacts Study,* prepared for Ameren Illinois Company in support of its refiled Multi-Year Integrated Grid Plan, March 2024, https://www.icc.illinois.gov/docket/P2023-0082/documents/348085/files/607911.pdf
NREL, Lawrence Berkeley National Laboratory, Kevala Inc., and U.S. Department of Energy, *Multi-State Transportation Electrification Impact Study: Preparing the Grid for Light-, Medium-, and Heavy-Duty Electric Vehicles*, DOE/EE-2818, U.S. Department of Energy, 2024, https://www.energy.gov/sites/default/files/2024-03/2024.03.18%20NREL%20LBNL%20Kevala%20DOE%20Multi-State%20Transportation%20Electrification%20Impact%20Study%20FINAL%20DOCKET.pdf

[5] Throughout the report, the scenario names may be abbreviated as follows: S1: Policy, S2: Goal, S2a: Mitigation - 50%, S2b: Mitigation - 100%, S3: Calibration, and S4: Adoption.

Kevala developed and analyzed a base load and six different scenarios for 2024-2050, including two with load flexibility, for this study.

Finally, using PSCo's distribution design guidance, Kevala estimated annual and cumulative costs for new grid assets to serve load related to load growth and DER adoption throughout the forecast period. Across the six scenarios modeled, these **costs[6] ranged from $21.0 billion for the Adoption Trajectory scenario to $51.2 billion for the Goal Aligned scenario** by 2050, with the Goal Aligned scenario requiring the most significant distribution grid investment (see Figure ES-1).

Figure ES-1: Cumulative nominal costs by year and scenario for all asset types: 2024-2050 (Source: Kevala)



Background and Context

PSCo filed its first Distribution System Plan (DSP) in May 2022 using a forecasting tool that considered a single scenario for planning distribution capacity investments. This forecasting approach relied primarily on historical load data and did not consider future adoption of load-modifying DERs.

[6] Costs include a 2.5% inflation increase per year after 2024.

The Colorado State Public Utilities Commission issued Proceeding No. 24M-0317EG on July 26, 2024, encouraging more explicit line-of-sight between PSCo's proposed investments and "the public policy goals declared in Senate Bill 24-218,"[7] including transportation electrification growth, building electrification, DER interconnection, and expanded capacity in disproportionately impacted communities. To address these legislative, regulatory, and stakeholder requirements, PSCo has made several changes to its DSP filing, including commissioning Kevala to conduct a study to complement and augment its DSP forecast.

Study Approach

Kevala used its EIM to conduct this study for 2024-2050. The EIM is a bottom-up forecasting approach that introduces stochastic variability on when and where loads will change due to weather and technology adoption. The high-level steps to this approach are outlined below:

1. **Prepare and ingest data:** Kevala ingested advanced metering infrastructure (AMI) data (where available), customer data (including class, billing history, and revenue class), geographic information system (GIS), and grid data into the Kevala platform.
2. **Simulate base load and forecast customer load growth:** Using a model trained on simulated AMI and climate data, Kevala generated a forecast of hourly energy use at the premise level that reflects weather conditions before any incremental DERs. The base load forecast used an extreme cold winter weather scenario based on publicly available data from the National Renewable Energy Laboratory (NREL) for all forecast years.[8]
3. **Create connectivity models:** Kevala mapped the topology of the electric grid from meter through to substation using GIS and hierarchy diagrams provided by PSCo.
4. **Estimate demand modifiers:** For the six scenarios with differing adoption and demand flexibility assumptions, Kevala forecasted changes to premise-level load from adoption of the following DERs based on PSCo-provided targets:
    a. Solar PV – behind-the-meter (BTM) PV and community solar gardens (CSG)
    b. Battery energy storage systems (BESS)
    c. Energy efficiency (EE)
    d. Demand response (DR)
    e. Electric vehicles (EVs)/electric vehicle service equipment (EVSE)
    f. Heat pump water heating (HPWH)
    g. Heat pump heating, ventilation, and air conditioning (HP HVAC)

[7] Initial Comments of Western Resource Advocates in Proceeding No. 24M-0317EG, August 20, 2024, p. 6.
[8] NREL, "Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC)," accessed through the Open Energy Data Initiative (OEDI), dataset last updated September 22, 2023, https://dx.doi.org/10.25984/1970814

5. **Develop premise-level net load and determine grid capacity needs:** Kevala aggregated base load and demand modifier adoption projections to develop premise-level net load forecasts. These forecasts were used to identify capacity needs due to overloads by service transformer, feeder, substation transformer bank, and substation.
6. **Quantify costs of capacity needs:** Kevala quantified costs of investments needed based on the grid capacity needs results using unit costs and distribution design principles provided by PSCo.

Note that this study was not designed to replace detailed engineering analysis or to reflect operational delivery of projects. This bottom-up study models more than 1 million premises on an hourly basis over decades. This process makes practical assumptions regarding consumer habits, technology performance, loading limits, and system design based on publicly accepted and Kevala proprietary methodologies. Design decisions for maintaining and updating specific elements of PSCo's distribution grid require analysis outside of the scope of this computationally driven demand growth study to enable reliable and safe energy delivery to PSCo's customers.

Results and Conclusions

To meet the state policy goals, including those modeled in the Goal Aligned scenario (Scenario 2), a significant amount of new infrastructure will be required to augment and expand PSCo's distribution system, including up to 170 new substations and 1,918 new feeders (see Figure ES-2). The Goal Aligned scenario sees a nearly five-fold increase in system coincident peak load across the forecast horizon (see Figure ES-3).

Figure ES-2: New assets (without service transformers) by scenario: 2024-2050 (Source: Kevala)

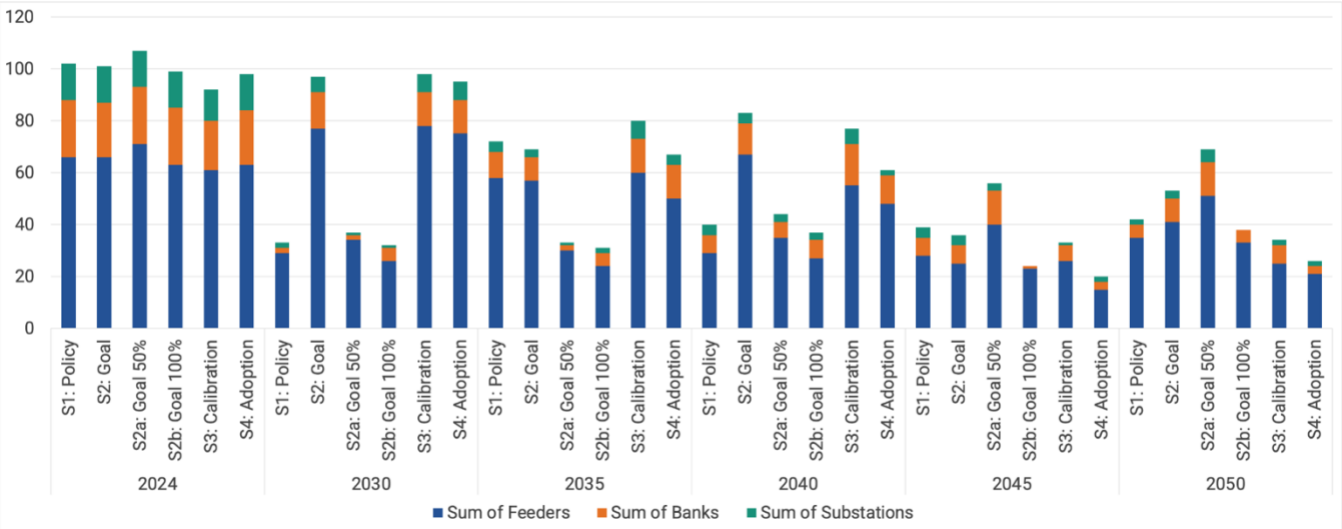
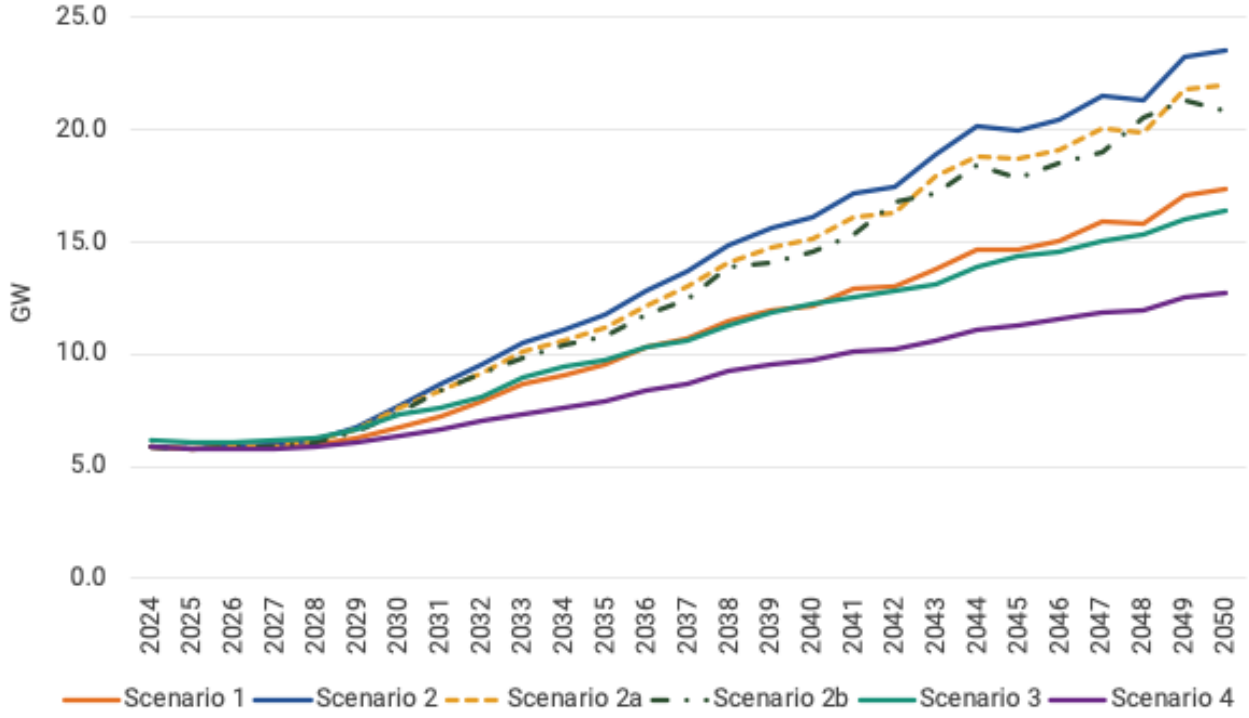


Figure ES-3: System net load with calculated losses (GW) by scenario: 2024-2050 (Source: Kevala)



The modeling approach enforced a 75% utilization factor (in accordance with PSCo system design policies), triggering a new build based on existing assets that exceed this threshold. While the logic in Kevala's model triggers a large number of assets in 2024, actual design and construction would likely be spread out over multiple years. Based on this modeling approach, necessary distribution system investments are similar for the next 5 years across each of the six scenarios modeled (see Figure ES-1).

By the early 2030s, the coincident system peak shifts to winter, while some feeders peak in the winter even earlier—by 2025, close to 30% of the feeders modeled in this study peak in the winter. This behavior can be explained by a large-scale migration from natural gas space and water heating to electric heat pump-based DERs. Scenarios with fewer and slower uptake of HP HVAC and HPWH units (such as the Adoption Trajectory Informed scenario) have a correspondingly slower migration from summer to winter system peaks.

While load flexibility and demand management programs can help mitigate some distribution infrastructure investment, the impacts of these programs as modeled in this study may be limited at scale without more aggressive technology deployment to more closely tie demand management to actual grid conditions, or program incentive design to shift additional demand off-peak for specific assets (e.g., feeders).

While this report is designed to summarize the methodology and results of this study, Kevala identified the following areas of future study:

- EV hourly charging profile assumptions have a large impact on feeder peak loads. As EV penetration increases and new customers with different use cases are added to the mix, validating assumptions for both non-managed and managed charging profiles across multiple use cases will be valuable.
- EV charging efficiency is highly temperature-dependent, and warrants additional consideration based on the findings in this study. In the most severe cases, LDV cab conditioning requirements can increase per-mile energy needs when temperatures fall below 0°F.[9]
- To simplify the analysis in this study, CSG was assumed to be curtailed to prevent high amounts of negative net load on any given feeder. However, Kevala understands that the current CSG program structure does not allow for active management of CSG through curtailment. This limitation indicates that, as modeled in this study, violations triggered by negative net load would likely result in additional infrastructure upgrades and/or downsizing of CSG projects. Future study could take a closer look at where CSG is likely to be adopted and consider the impact of co-locating grid-scale BESS with CSG projects, which may partially mitigate this concern.
- Beyond EV management, it may be interesting to contemplate the impacts of programs to pre-heat homes ahead of peak hours or incentivize larger capacity BESS adoptions and schedule discharge to mitigate space heating peaks. Kevala's methodology could be refined to explicitly model impacts of HP HVAC efficiency gains or building insulation investments.

In general, Kevala used the data available and informed assumptions about specific distributed energy technologies and behaviors developed with PSCo over the summer of 2024. While Kevala anticipates that the results of this analysis can be refined in future iterations, this initial study provides PSCo and its stakeholders an informed lens into future potential electric distribution grid requirements.

[9] Argue, Charlotte, "To what degree does temperature impact EV range?" Geotab, November 30, 2023, https://www.geotab.com/blog/ev-range/

1. Introduction

Using its Electrification Impacts Model (EIM), Kevala, Inc. (Kevala) modeled multiple scenarios that incorporate varied assumptions of demand modifiers to estimate where and when capacity shortfalls may occur on the Public Service Company of Colorado's (PSCo's) distribution system. The study is designed to understand the range of potential locational capacity requirements, in the near term and out through 2050, that may be necessary to support customer adoption of distributed energy resources (DERs) in pursuit of state and local electrification goals for numerous electrification technologies.

For this ambitious study, PSCo asked Kevala to go beyond the assumptions, tools, and forecast period applied in traditional system forecasting for distribution planning, and examine six distinct adoption and demand flexibility scenarios of seven DER technologies (i.e., demand modifiers). These scenarios reflect not only the different DER penetration and deployment goals reflected across PSCo's service territory, but also load flexibility assumptions for how those DERs might help to smooth their impact on the distribution grid. PSCo also asked Kevala to forecast the grid impacts of each scenario through 2050, recognizing that distribution planning and investment of capital to meet decarbonization goals will, in some cases, require long lead times and stakeholder input.

This study explored the following seven demand modifiers:

- Solar photovoltaics (PV) – behind-the-meter (BTM) PV and community solar gardens (CSG)
- Battery energy storage systems (BESS)
- Energy efficiency (EE)
- Demand response (DR)
- Electric vehicles (EVs) and electric vehicle service equipment (EVSE)
- Heat pump water heating (HPWH)
- All-electric heat pump heating, ventilation, and air conditioning (HP HVAC)[10]

1.1 Context and Objectives

PSCo filed its first Distribution System Plan (DSP) in May 2022. Kevala understands that the load forecasting and modeling approach underlying the 2022 Plan was completed using a forecasting tool that considered a single scenario for planning distribution capacity investments. Additionally,

[10] This study did not model dual-fuel heat pump adoptions or shifts from dual-fuel heat pumps to all-electric models. This modeling decision reflects PSCo's interest in modeling worst-case distribution conditions during severe cold, when dual-fuel heat pumps would otherwise use gas backup.

the forecasting approach relied primarily on historical load data and did not incorporate load impacts related to future adoption of DERs.

The Colorado State Public Utilities Commission issued Proceeding No. 24M-0317EG on July 26, 2024, to consider future filings by PSCo related to distribution system funding. In the context of that proceeding, stakeholders have encouraged more explicit line-of-sight between PSCo's proposed investments and "the public policy goals declared in Senate Bill 24-218,"[11] including transportation electrification growth, building electrification, DER interconnection, and expanded capacity in disproportionately impacted communities.

To address these legislative, regulatory, and stakeholder requirements, PSCo has made several changes to its planning and forecasting processes since its first DSP filing. First, Kevala understands that PSCo has updated its tools to develop its base forecast, capacity projects, and distribution capital budget forecast for 2024. In addition, PSCo commissioned Kevala to complement and augment its base DSP forecast, with forward-looking projections of DER adoption and customer behavior. PSCo worked with Kevala to develop six distinct scenarios to better understand the potential implications of future customer adoption of DERs driven by factors that include binding state policies, more aspirational state policy goals, and current customer adoption patterns.

For this analysis, Kevala used the data available and numerous informed assumptions about specific distributed energy technologies and behaviors developed with PSCo over the summer of 2024. While Kevala anticipates that the results of this analysis can be refined in future iterations—for example, to incorporate additional and updated datasets as they become available, incorporate even more technology-specific adoption assumptions, and/or apply additional utility programmatic or rate design mitigations (see Section 4)—this initial study provides PSCo and its stakeholders an informed lens into future potential electric distribution grid requirements.

1.2 Report Outline

This report is broken into the following sections:

- Section 2 describes the approach for this study, including an overview of Kevala's EIM and the study's six scenarios.
- Section 3 discusses the study's results and key findings, including estimated costs by scenario based on capacity needs.
- Section 4 highlights Kevala's key findings from the scenario analysis as well as areas for future study.

[11] Initial Comments of Western Resource Advocates in Proceeding No. 24M-0317EG, August 20, 2024, p. 6.

The appendices provide detailed information on the study's methods and results, including the data used, how the base load forecast was developed, the approach to determining capacity needs and cost estimates, and methodology explanations for each demand modifier and detailed results for each based on the scenario outcomes.

2. Study Approach

Kevala used a bottom-up approach that introduces stochastic variability to determine when and where loads will change on the distribution system.[12] This approach focuses on individual premise loads and how they change over time based on different policy- and goal-aligned scenarios. This type of approach provides transparency into how demand modifiers can, individually and collectively, modify the shape of feeder and substation loads, when these changes occur, and what distribution grid upgrades may be required to meet these loads.

2.1 Electrification Impacts Model Overview

The project's approach used Kevala's EIM (see Figure 1), which consists of multiple steps to forecast the generation and load impact from demand modifiers based on adoption models that are run at a granular level—in this case at the premise level—and aggregated up to determine the impact at higher aggregation levels such as service transformers, feeders, transformer banks, substations, or an entire service territory.

Kevala's electrification impact modeling differs from most traditional distribution planning approaches in three key ways:

1. Kevala models a base load forecast for each of the 8760 hours of the year for each premise. Kevala models this hourly forecast for each premise by acquiring and collating all available usage, revenue class, and demographic data about each premise. This bottom-up approach recognizes that, especially in the current dynamic distributed energy technology environment, customer adoption and behavior profiles are not homogeneous.
2. Kevala incorporates multiple scenarios into its analysis that reflect distinct local energy and technology policy goals and preferences across a utility's service territory.

[12] Kevala previously conducted studies using similar bottom-up scenario analysis approaches, including:
Kevala, Inc., *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates*, prepared for the California Public Utilities Commission, Energy Division for Proceeding R.21-06-017 (Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future), May 9, 2023, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF
Kevala, Inc., *Appendix Q: Electrification Impacts Study,* prepared for Ameren Illinois Company in support of its refiled Multi-Year Integrated Grid Plan, March 2024, https://www.icc.illinois.gov/docket/P2023-0082/documents/348085/files/607911.pdf
NREL, Lawrence Berkeley National Laboratory, Kevala Inc., and U.S. Department of Energy, *Multi-State Transportation Electrification Impact Study: Preparing the Grid for Light-, Medium-, and Heavy-Duty Electric Vehicles*, DOE/EE-2818, U.S. Department of Energy, 2024, https://www.energy.gov/sites/default/files/2024-03/2024.03.18%20NREL%20LBNL%20Kevala%20DOE%20Multi-State%20Transportation%20Electrification%20Impact%20Study%20FINAL%20DOCKET.pdf

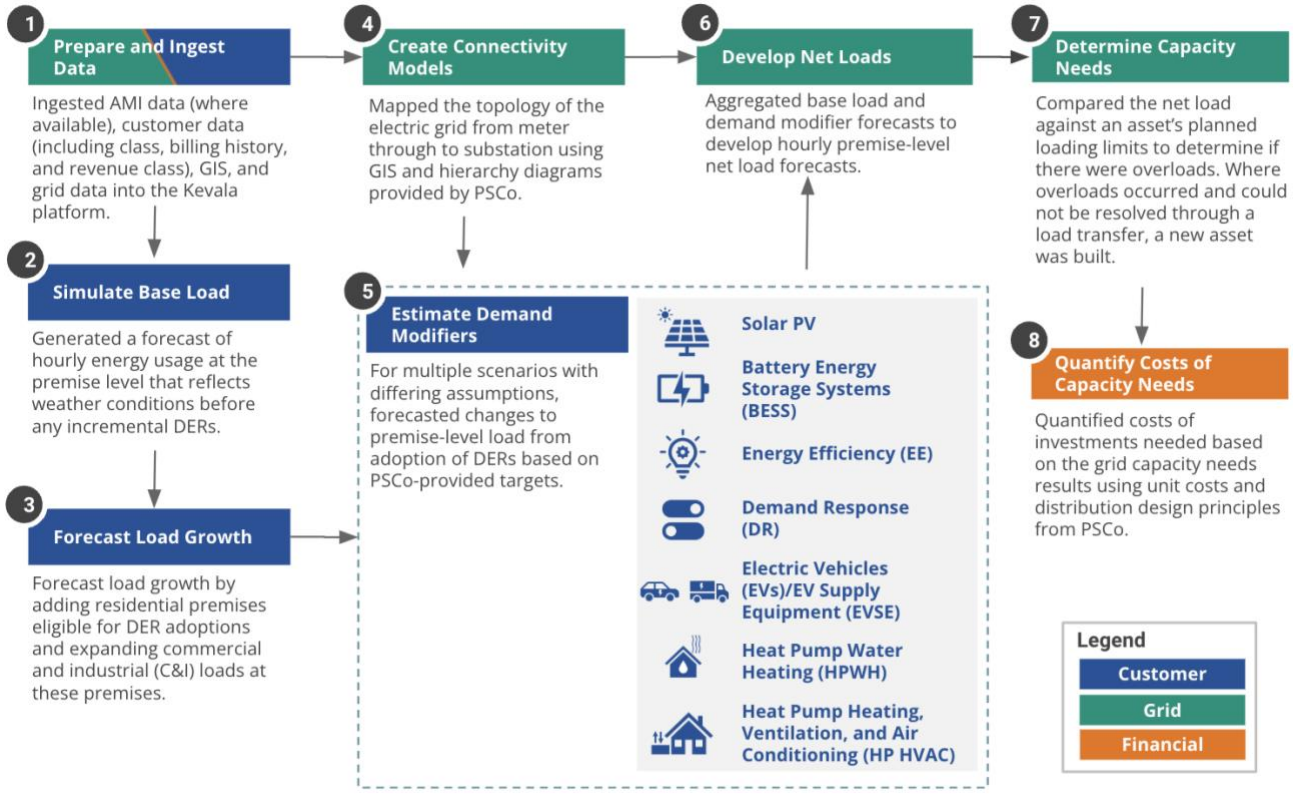
3. Kevala's approach extends the forecast period beyond the traditional 5-to-10-year regulatory distribution planning or rate case cycle, which enables planners to most efficiently and equitably deploy distribution infrastructure capital with the benefit of a longer-term view of distribution grid requirements.

This approach results in distribution planning insights into the location-specific distribution grid needs of today's grid as well as how those needs are likely to change as future DER adoption rates evolve. It also increases the transparency, or line-of-sight, between proposed and needed grid investments, and state and local policy goals and requirements. This transparency allows decision makers to understand where investments are needed across a longer forecast horizon and build the right sized equipment for upgrades to suit both near- and long-term needs, avoiding frequent rebuilds of the same infrastructure. Key features of Kevala's results from this analysis include:

- Allows for the aggregation of premise-level loads to different levels of distribution infrastructure assets and provides insights into how premise-specific loads can change the loads on feeders.
- Allows for an assessment of the relative contribution-to-peak of different DERs at different distribution infrastructure levels of the electricity grid and at different times.
- Reflects that customer adoption of DERs and other technologies can impact peak loads in very different ways over time, and that these changes are not homogenous across customers.
- Enables investment decision makers and stakeholders to evaluate the impact of localized DERs and policy goals on the infrastructure that serves their communities.

Each step of the EIM is discussed further below and in detail in the report's appendices.

Figure 1: Kevala's Electrification Impacts Model tailored to this study (Source: Kevala)



Note that this study was not designed to replace detailed engineering analysis or to reflect operational delivery of projects. This bottom-up study models more than 1 million premises on an hourly basis over decades. This process makes practical assumptions regarding consumer habits, technology performance, loading limits, and system design based on publicly accepted and Kevala proprietary methodologies. Design decisions for maintaining and updating specific elements of PSCo's distribution grid require analysis outside of the scope of this computationally driven demand growth study to enable reliable and safe energy delivery to PSCO's customers.

2.1.1 Prepare and Ingest Data

To start, Kevala ingested data provided by PSCo, including geographic information system (GIS) data, equipment and asset characteristics and costs. PSCo also provided near-term peak capacity forecasts based on current PSCo grid capacity measurements. Additionally, PSCo supplied Kevala with multiple years of billing data and advanced metering infrastructure (AMI) data for some customer types. For more detail, including lists of the data used for this study, see Appendix A.

2.1.2 Simulate Base Load and Forecast Customer Load Growth

Kevala developed the base load forecast using a tree-based regression model trained on simulated AMI and climate data. Specifically, Kevala generated a forecast of hourly energy use for each premise that reflects weather conditions before any incremental DERs. Per PSCo's request,

Kevala used an extreme cold winter weather scenario based on the NREL Sup3rCC dataset for all forecast years.[13] By using an extreme cold weather year, this study was designed to model the severity of cold weather impacts on heating loads, which PSCo believes will be more aggressively electrified in the coming decade given policy goals and incentives in several Colorado communities.

Using its load growth model, Kevala then calculated load growth from the year-over-year percent change in net energy forecast, which was then applied to the base load forecast on gross energy. The model created new residential premises and increased the demand of commercial and industrial (C&I) premises according to PSCo's system load forecast from the DSP.

Finally, Kevala calibrated peak demand to PSCo's 2024 planning peaks by aggregating the base load forecasts by feeder, applying losses, and applying a calibration factor based on PSCo DSP forecast. This calibration exercise helped validate the starting conditions against which Kevala modeled future DER and load growth were similar to PSCo's current system loadings. For specific assumptions used to develop the base load forecast, see Appendix B.

2.1.3 Create Connectivity Models

Using the data collected from PSCo (see Appendix A for a full list of the data and the total number of assets modeled in this study), Kevala mapped the topology of the grid to enable proper aggregation of premise-specific data to grid infrastructure and linking known DERs to the grid. The GIS and hierarchy diagrams provided by PSCo were critical to associating the consumption at a meter to the electrical infrastructure via a many-to-one match to a premise (i.e., many meters could be associated to a premise).

2.1.4 Estimate Demand Modifiers

Kevala predicted each demand modifier's characteristics (also referred to as size), behavior (energy time series profile), and adoption (i.e., did a premise experience the demand modifier size and behavior implications?) using its proprietary customer adoption models. The adoption predictions for each demand modifier were calibrated according to PSCo-defined top-level targets for each scenario. The six scenarios analyzed in this study showcase different potential policy- and goal-aligned outcomes (see Section 2.2) through the different sets of adoption targets.

The following demand modifiers were included in this study:

- Solar photovoltaics (PV) – behind-the-meter (BTM) PV and community solar gardens (CSG)

[13] NREL, "Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC)," accessed through the Open Energy Data Initiative (OEDI), dataset last updated September 22, 2023, https://dx.doi.org/10.25984/1970814

- Battery energy storage systems (BESS)
- Energy efficiency (EE)
- Demand response (DR)
- Electric vehicles (EVs) and electric vehicle service equipment (EVSE)
- Heat pump water heating (HPWH)
- All-electric heat pump heating, ventilation, and air conditioning (HP HVAC)

For more detail on each demand modifier's specific modeling methodology and additional demand modifier-specific results, see Appendix F through Appendix L.

2.1.5 Develop Net Loads and Determine Grid Capacity Needs

Kevala aggregated the base load and demand modifier forecasts to develop hourly premise-level net load forecasts. These net loads were aggregated based on the connectivity models to develop forecasts by grid asset type (i.e., service transformer, feeder, substation transformer bank, and substation). Kevala then compared the net load against an asset's thermal equipment rating to determine if there were capacity violations (referred to as overloads) associated with normal or contingency capacity limits. Where overloads occurred and could not be resolved through load transfers to a nearby asset with adequate remaining capacity, a new asset was modeled or "built" to be in service for the remainder of the analysis. See Appendix C and Appendix D for more detail, including assumptions about load transfers, capacity limits, design principles, and asset sizing.

2.1.6 Quantify Costs of Capacity Needs

Kevala quantified the costs of the investments needed based on the overload results calculated in the previous step. Kevala's method was based on unit costs of grid assets in the year the overload was identified. New asset unit costs did not include the buildout of additional "coupled" assets; for example, when a feeder was required at a substation without any physical capacity remaining for an incremental feeder, Kevala's approach incurred costs for a new feeder, a new transformer bank, and a new substation.

All costs shown in this report are considered nominal with a 2.5% yearly inflation rate applied to each year after 2024. Asset costs were broken down to include an urbanization categorization, acknowledging differences in construction and installation costs between rural, urban, or dense urban areas. Appendix E provides more detail, including the specific cost assumptions Kevala used.

2.2 Scenario Analysis

Kevala analyzed several scenarios of DER and other demand modifier assumptions at the premise level. System-level estimated adoptions of demand modifiers were provided to Kevala by PSCo. Kevala then spatially allocated these adoption targets to premises and specific distribution assets

using the EIM methodology across the entire service territory. This approach contextualizes current and future potential investment decisions across multiple potential policy- and goal-aligned outcomes.

Kevala ran premise-level adoption forecasts across six scenarios. Adoptions in each scenario are independent of the other scenarios. Four of these scenarios are unmitigated, long-term scenarios, meaning the scenarios project customer DER adoption and behavior without additional influence or mitigation measures such as managed charging. Kevala applied two separate load flexibility adjustments to Scenario 2, the Goal Aligned scenario. These additional scenarios demonstrate the impact of modified EV charging behaviors (through programs or incentives) on locational noncoincident peak needs at the distribution substation and feeder levels. The six scenarios analyzed in this report are detailed below:

- **Scenario 1 – Policy Aligned:** Meets load growth and DER adoptions associated with updated Colorado state and local binding energy policies or legislative mandates, including Energize Denver, legislation requiring gas utilities file Clean Heat Plans, and the Boulder County all electric requirements for new construction and major renovations.[14]
- **Scenario 2 – Goal Aligned:** Includes growth to meet Colorado state and municipal decarbonization goals through 2050.[15]
    - **Scenario 2a – Goal Aligned, Mitigation Scenario A:** Using the Scenario 2 demand modifier targets, includes 50% managed charging for fleet and personal EV charging.
    - **Scenario 2b – Goal Aligned, Mitigation Scenario B:** Using the Scenario 2 demand modifier targets, includes 100% managed charging for fleet and personal EV charging.
- **Scenario 3 – Calibration:** Meets load growth in line with PSCo's current DSP forecast.
- **Scenario 4 – Adoption Trajectory:** Provides a business-as-usual forecast based on PSCo's perspective informed by historical adoption rates and customer demands.[16]

The load flexibility scenarios (2a and 2b) were designed to reflect customer-driven behavior to minimize a local peak at their meter by shifting load away from the system's coincident peak. Kevala focused on transportation electrification[17] for these mitigations, given currently deployed

[14] For more information on these policies and mandates, see: Denver Council Bill 21-1310, Colorado General Assembly Senate Bill 21-264, and the City of Boulder 2024 Energy Conservation Code Update.
[15] Decarbonization goals from the City of Denver's 80 x 50 Climate Action Plan and Colorado's Greenhouse Gas Pollution Reduction Roadmap, among others.
[16] Throughout the report, the scenario names may be abbreviated as follows: S1: Policy, S2: Goal, S2a: Mitigation - 50%, S2b: Mitigation - 100%, S3: Calibration, and S4: Adoption.
[17] In previous studies, Kevala has analyzed the impacts of EV charging on the grid. When unmanaged, EV charging has the potential to further increase existing summer evening system coincident peaks. The scale

technologies, consumer trends, and program architecture.[18] Fleet and personal vehicles were used in these scenarios as they are more adaptable and responsive to economic incentives. In contrast, public, workplace, and corridor (PWC) chargers are less likely to be responsive to economic incentives given the inherent characteristics of the populations they serve and the locations in which they are sited.

of the impact can vary depending on the details of the approach. See the *Electrification Impacts Study Part 1* for the California Public Utilities Commission and the Transportation Electrification Impact Study.

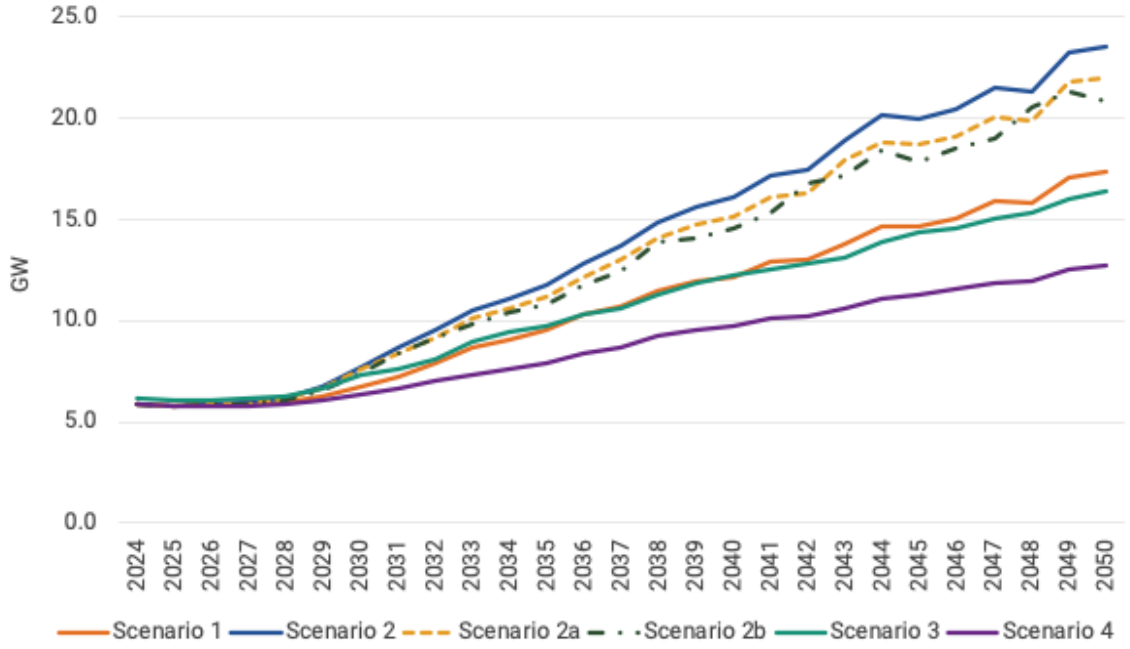
[18] Other peak reductions were estimated via the DR demand modifier for each scenario (see Appendix I).

3. Results, Analysis, and Key Findings

3.1 Results

Figure 2 shows the system coincident peak net loads (including calculated losses)[19] for each scenario from 2024-2050. All of the scenarios start at the same point, mirrored to the PSCo's DSP. Starting in 2028, the net loads diverged significantly with the three variations of Scenario 2 (2, 2a, and 2b), which include load flexibility (i.e., managed EV charging), showing the greatest increases in net load on system coincident peak days.

Figure 2: System coincident peak net load with calculated losses (GW) by scenario: 2024-2050 (Source: Kevala)



While Figure 2 shows gross impacts of load growth and DER adoptions on PSCo's distribution system, using bottom-up calculations to determine hourly load for a service territory also provides the granularity to review and analyze individual assets and their load and peak. Table 1 shows five substations' noncoincident peak net load by scenario and year. Kevala identified these substations as needing the highest number of assets to be built based on capacity overloads.[20, 21]

[19] All losses were calculated on demand and demand modifiers at a rate of 5.855%. Unless otherwise noted, load results shown in this report include losses.
[20] While Figure 2 shows coincident system peaks, as discussed in Appendix D, Kevala's capacity upgrade approach considers noncoincident peak demands for assets.
[21] As more capacity is required in later forecast years due to load growth, these aggregate noncoincident peak demand values are spread across additional new assets that Kevala models building. These values are

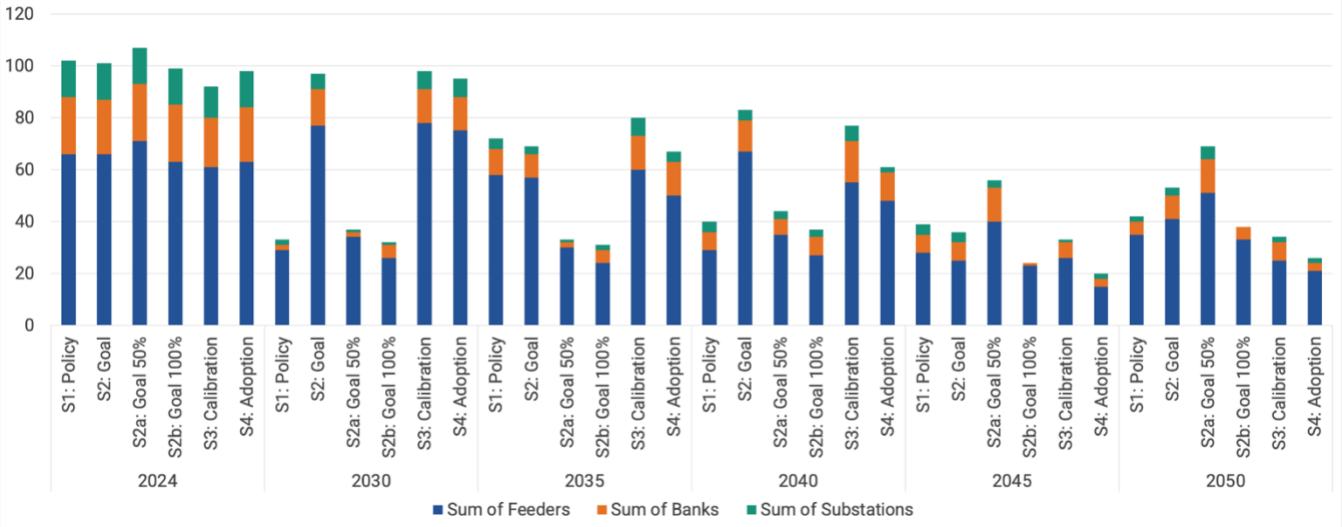
Table 1: Noncoincident peak net loads with losses (kW) for five substations by scenario: 2024-2050 (Source: Kevala)

Substation	Scenario	2024	2030	2035	2040	2045	2050
East	S1: Policy	113,044	141,957	215,113	274,229	337,368	399,190
	S2: Goal	113,810	159,986	256,277	370,664	488,718	551,494
	S2a: Goal – Mitigation 50%	114,142	167,697	260,156	358,507	468,144	510,538
	S2b: Goal – Mitigation 100%	114,012	151,166	233,266	337,304	428,518	498,878
	S3: Calibration	119,333	155,374	215,327	273,443	327,129	372,106
	S4: Adoption	113,355	136,743	188,344	229,208	272,915	303,804
Boulder Terminal	S1: Policy	84,642	115,313	180,652	239,480	294,890	366,884
	S2: Goal	84,313	137,772	222,597	324,302	403,279	485,091
	S2a: Goal – Mitigation 50%	83,308	136,402	224,428	317,893	387,238	452,029
	S2b: Goal – Mitigation 100%	84,286	136,320	226,562	308,664	383,481	453,620
	S3: Calibration	89,306	117,779	181,021	241,771	295,825	347,320
	S4: Adoption	83,990	100,149	131,394	166,719	201,435	246,379
Federal Heights	S1: Policy	108,117	126,022	184,360	237,109	296,651	364,422
	S2: Goal	108,157	139,608	216,447	297,256	384,718	476,236
	S2a: Goal – Mitigation 50%	108,232	137,860	208,684	284,471	362,612	447,382
	S2b: Goal – Mitigation 100%	108,321	129,302	194,419	262,101	333,534	407,391
	S3: Calibration	113,344	129,513	185,384	239,870	286,454	333,689
	S4: Adoption	108,007	122,252	145,597	187,808	220,865	254,745
Leetsdale	S1: Policy	101,190	120,917	182,483	252,039	303,072	354,802
	S2: Goal	101,069	138,456	218,160	321,504	401,546	467,299
	S2a: Goal – Mitigation 50%	101,413	133,321	208,162	306,921	377,174	444,230
	S2b: Goal – Mitigation 100%	100,940	134,365	209,330	292,102	360,528	425,096
	S3: Calibration	107,271	124,611	177,646	232,623	280,489	334,194
	S4: Adoption	100,771	115,997	138,064	181,428	215,094	244,959
South	S1: Policy	85,081	111,015	164,016	209,369	252,938	312,576
	S2: Goal	84,523	137,028	228,096	319,855	378,780	438,640
	S2a: Goal – Mitigation 50%	84,445	132,865	196,650	316,089	371,942	421,716
	S2b: Goal – Mitigation 100%	83,888	165,730	214,557	299,392	359,426	402,489
	S3: Calibration	89,227	116,954	156,612	205,036	241,719	286,584
	S4: Adoption	84,939	97,939	123,361	160,281	176,439	200,664

meant to illustrate the peak demand that would theoretically be served by these substations and their constituent assets if they had unlimited hosting capacity.

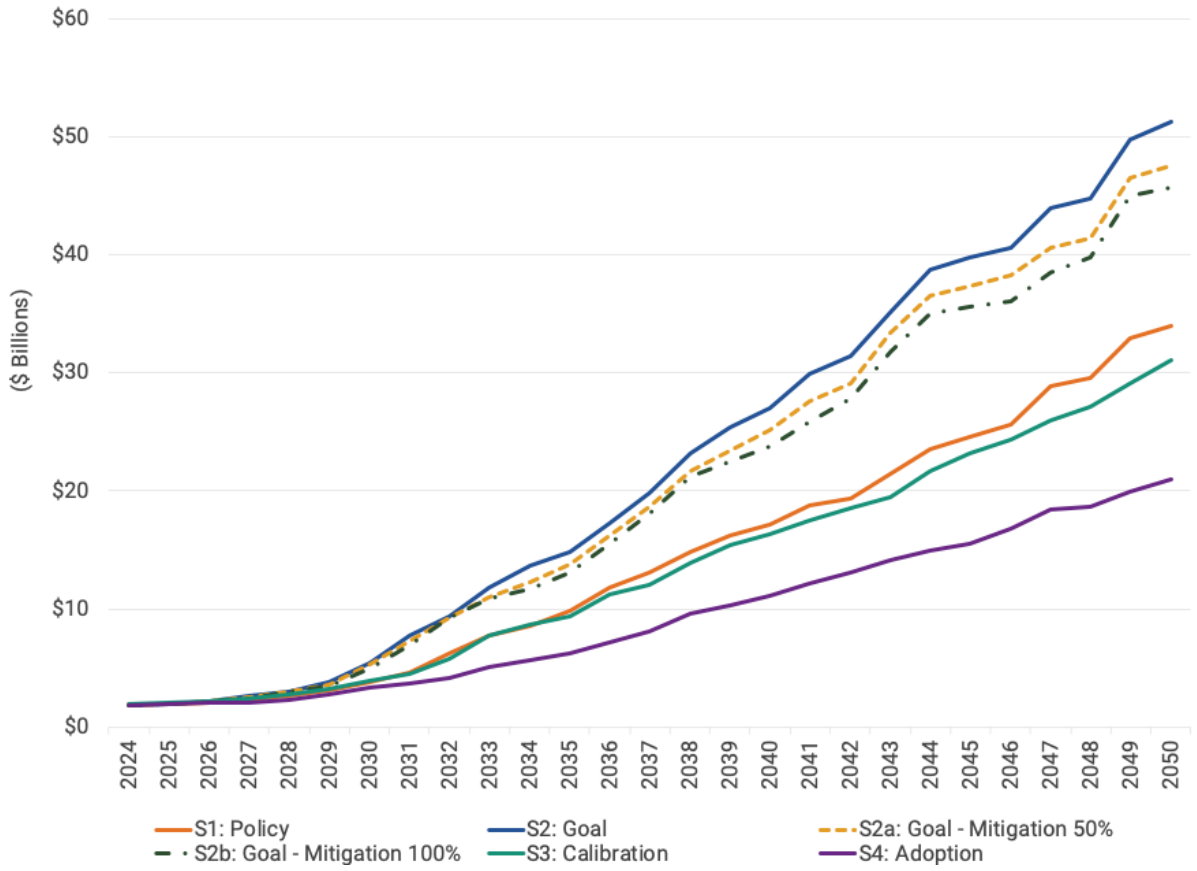
Figure 3 shows counts of new assets for each scenario by five-year increments. This asset count includes feeders, service transformer banks, and substations identified through the capacity analysis to enable new load (see Appendix D for service transformer asset counts). The Goal Aligned scenarios (S2, S2a, and S2b) had the highest asset counts in line with their increased adoption targets and load growth.

Figure 3: New assets (without service transformers) by scenario: 2024-2050 (Source: Kevala)



As Figure 4 shows, the cumulative nominal costs for all assets increased similarly across scenarios until around 2030. From that year onward, the cost and growth of the Goal Aligned scenarios (2, 2a, and 2b) were significantly higher than the other scenarios. The curves of those higher growth, higher cost scenarios reflected each other with the reductions in costs being directly related to the impacts of managed charging on infrastructure needs. Each year after 2024 experienced a 2.5% inflation increase.

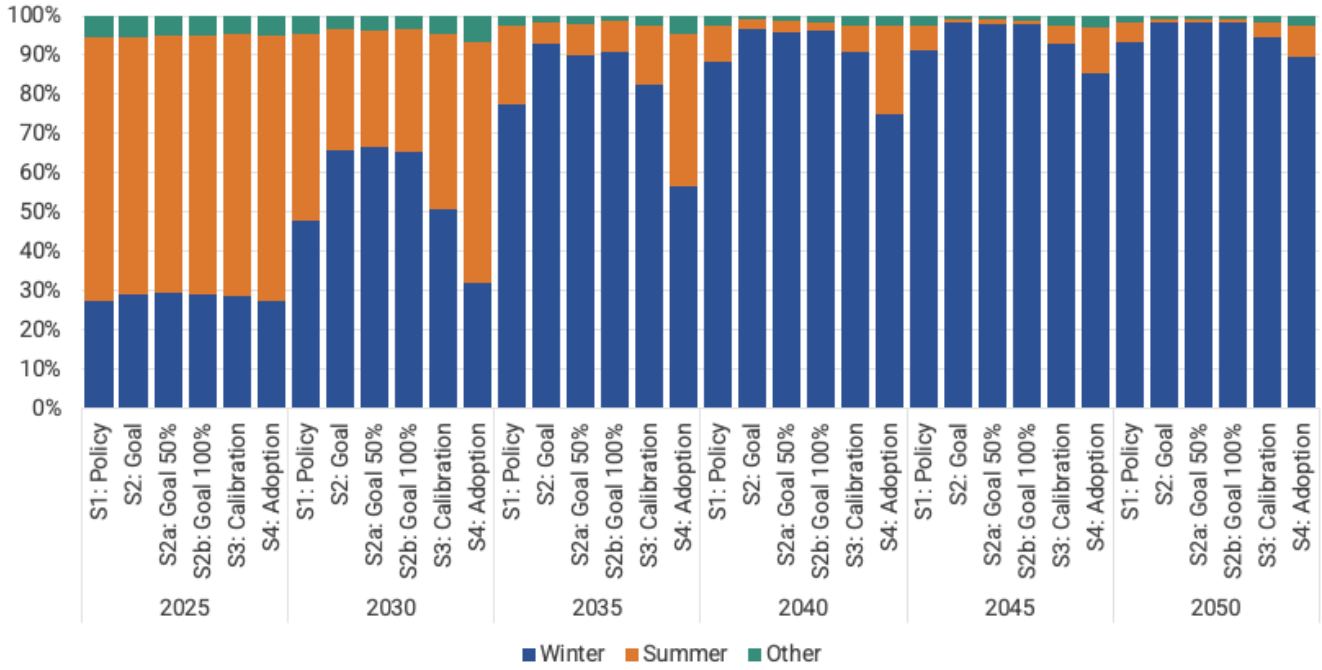
Figure 4: Cumulative nominal costs by year and scenario for all asset types: 2024-2050 (Source: Kevala)



3.2 Analysis and Key Findings

Across all scenarios, in the early-to-mid 2030s, adoption of heat pump technologies for water and space heating shifts PSCo's coincident distribution system coincident peak from summer to winter (see Figure 5). Winter months are defined as December through March and summer months defined as June through September. This shift to a winter peak will have major implications on the gas system, and peak sensitivity to severely cold weather will require different planning and operational tools (e.g., expanded/new DR programs).

Figure 5: Percentage of system net load peak days by season and scenario: 2025-2050 (Source: Kevala)



EV operation during severe weather events can vary dramatically, given battery conditioning and cab climate control needs, which require battery capacity that would otherwise be used for miles traveled. In the most severe case, a vehicle can require more than twice the energy to travel the same distance as in optimal temperature conditions.[22] This trend is borne out in the results of this study, and is acutely present for light-duty vehicles, leveraged by personal and fleet segments, with significant seasonal impacts on both demand and sales for vehicles without variability in seasonal mileage. Specific programs, such as flexible interconnection and aggressive time-of-use rates for fleet operators and homeowners, may be used to mitigate these impacts.

CSG adoption targets (between 2.3 GW and 2.6 GW, depending on the scenario) appear relatively high (see Figure 6). In the highest adoption scenario (Scenario 2), this study found a clustering of eligible premises on 106 of more than 800 feeders.[23] This resulted in those feeders experiencing significant backflow during peak CSG production times. In the absence of any interventions, this CSG production would result in distribution assets with high amounts of negative net load. To simplify the analysis in this study, CSGs were assumed to be curtailed to prevent high amounts of negative net load on any given feeder. However, Kevala understands that the current CSG program structure does not allow for active management of CSG through curtailment. This limitation indicates that, as modeled in this study, violations triggered by negative net load would

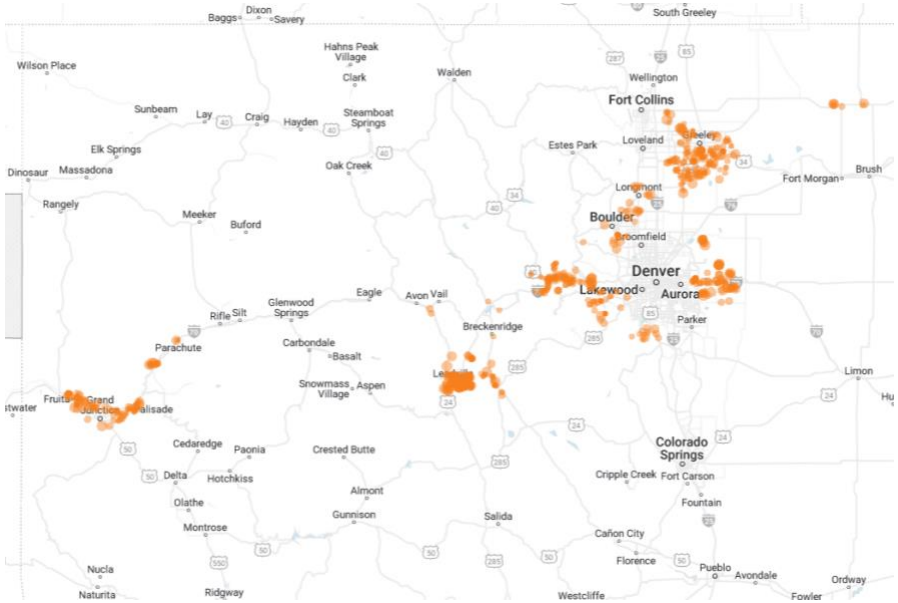
[22] Argue, Charlotte, "To what degree does temperature impact EV range?" Geotab, November 30, 2023, https://www.geotab.com/blog/ev-range/

[23] See Appendix F for additional information regarding CSG eligibility.

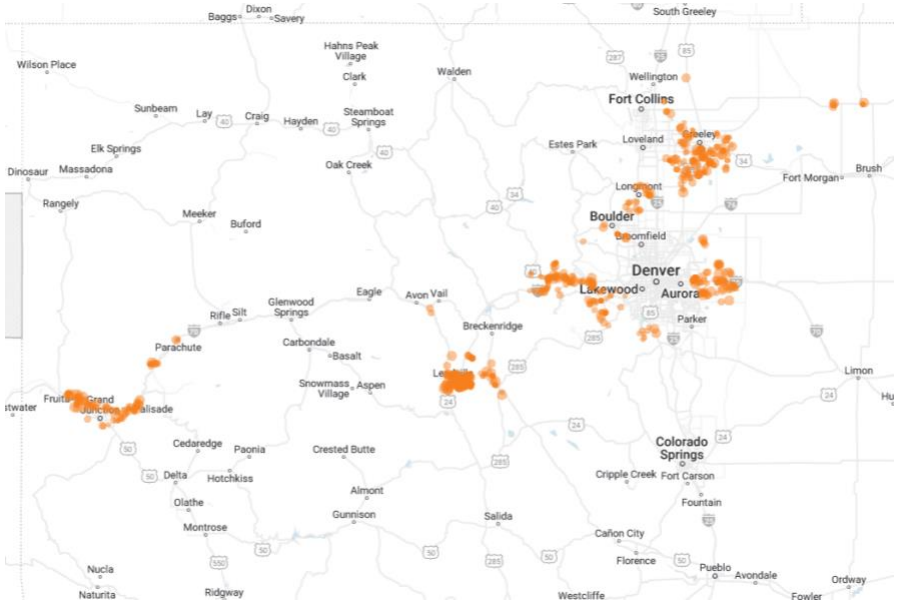
likely result in additional infrastructure upgrades and/or downsizing of CSG projects. This phenomenon illustrates that distribution-level coordination will be required to effectively deploy CSG in PSCo's service territory at such high volumes. Further, matching CSG only to feeders with excess capacity and cheap, available land will create significant distribution interconnection cost burdens, as corresponding local demand at midday (i.e., during peak PV production) will not always be guaranteed.

Figure 6: CSG system adoption across PSCo's service territory, Scenario 2 (Policy Aligned) vs. Scenario 3 (Calibration): 2024-2050 (Source: Kevala)

Scenario 2: Goal Aligned



Scenario 3: Calibration



Note: Larger dots correspond to larger CSG systems. Systems are 500 kW-5,000 kW.

In the demand flexibility scenarios, 2a and 2b, EV charging was assumed to be migrated off the local premise's peak for both fleet and personal light-duty vehicle segments for 50% and 100% of the vehicles in each scenario respectively. This had the expected impact of decreasing noncoincident peaks and thus distribution capacity investments in Scenario 2b (100% management) below those same investments in Scenario 2a (50% management). However, the noncoincident peak in some early forecast years was larger in 2a than 2b due to fewer hours during which the vehicle segment could be expected to charge, resulting in earlier investment requirements for certain distribution assets. This illustrates the need for dynamic charge management, which considers current grid conditions before dispatching charging signals to candidate vehicles.[24]

In these scenarios (2a and 2b), the HPWH load shape, with low levels of load during late evening to early morning hours, is somewhat complimentary to managed personal EVSE demand, which tends to appear at the same time. Further, the load shape is complementary to solar PV, where HPWH load tends to be higher when solar PV systems are generating power. Complementary strategies among HWPH, solar PV, and personal EVSE adoption could allow for better utilization factors for residential customers. This same phenomenon carries to HP HVAC systems, adoptions of which (alongside solar PV and personal EVs) could benefit distribution planning—customers could be incented to manage their energy use to improve utilization and flatten loads rather than adding to noncoincident peak loads.

Figure 7 shows system-level net loads for the scenarios with the same targets but including load flexibility. Scenario 2, without managed charging efforts, increased and remained the highest net load of the three scenarios. Scenario 2a and 2b grew at roughly the same rate; however, the higher managed charging effort in Scenario 2b kept net load lower than Scenario 2 and 2a.

[24] Kevala contemplated and modeled a distribution-aware EV charge management paradigm as part of the U.S. Department of Energy's Transportation Electrification Impact Study. See Appendix E of the study: NREL, Lawrence Berkeley National Laboratory, Kevala Inc., and U.S. Department of Energy, *Multi-State Transportation Electrification Impact Study: Preparing the Grid for Light-, Medium-, and Heavy-Duty Electric Vehicles*, DOE/EE-2818, U.S. Department of Energy, 2024, https://www.energy.gov/sites/default/files/2024-03/2024.03.18%20NREL%20LBNL%20Kevala%20DOE%20Multi-State%20Transportation%20Electrification%20Impact%20Study%20FINAL%20DOCKET.pdf

Figure 7: System-level net loads for the Goal Aligned scenarios (2, 2a, and 2b): 2024-2050 (Source: Kevala)

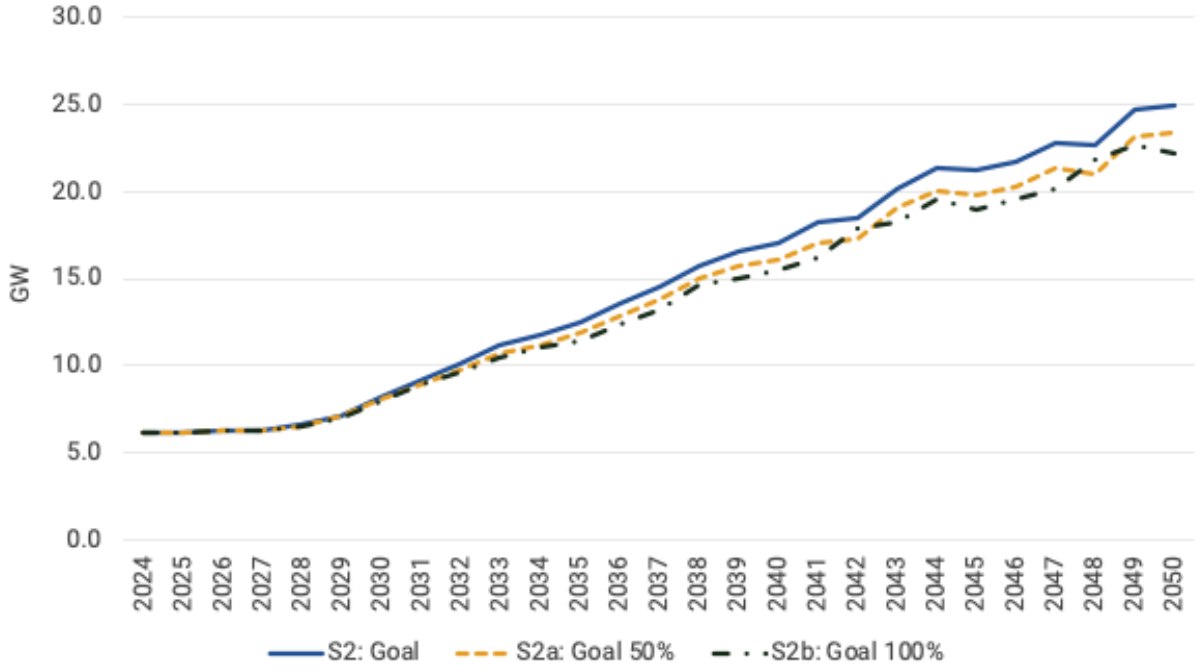


Figure 8 shows counts of new feeder builds for the five substations with the largest-scale capacity increases by the end of the study, while Figure 9 shows the same counts for substation transformer banks. Across all scenarios, Kevala consistently identified investment needs for these substations, and, in most scenarios, increasing demand precipitated significant investments throughout the study period. The areas served by these substations may be good candidates for immediate-term PSCo capacity projects. Further, Kevala's results validate PSCo's approach to new asset development, whereby a new substation is initially built out to support not only current but also future forecasted demand.

Figure 8: Count of new feeders required for the top five substations by 2050 (Source: Kevala)

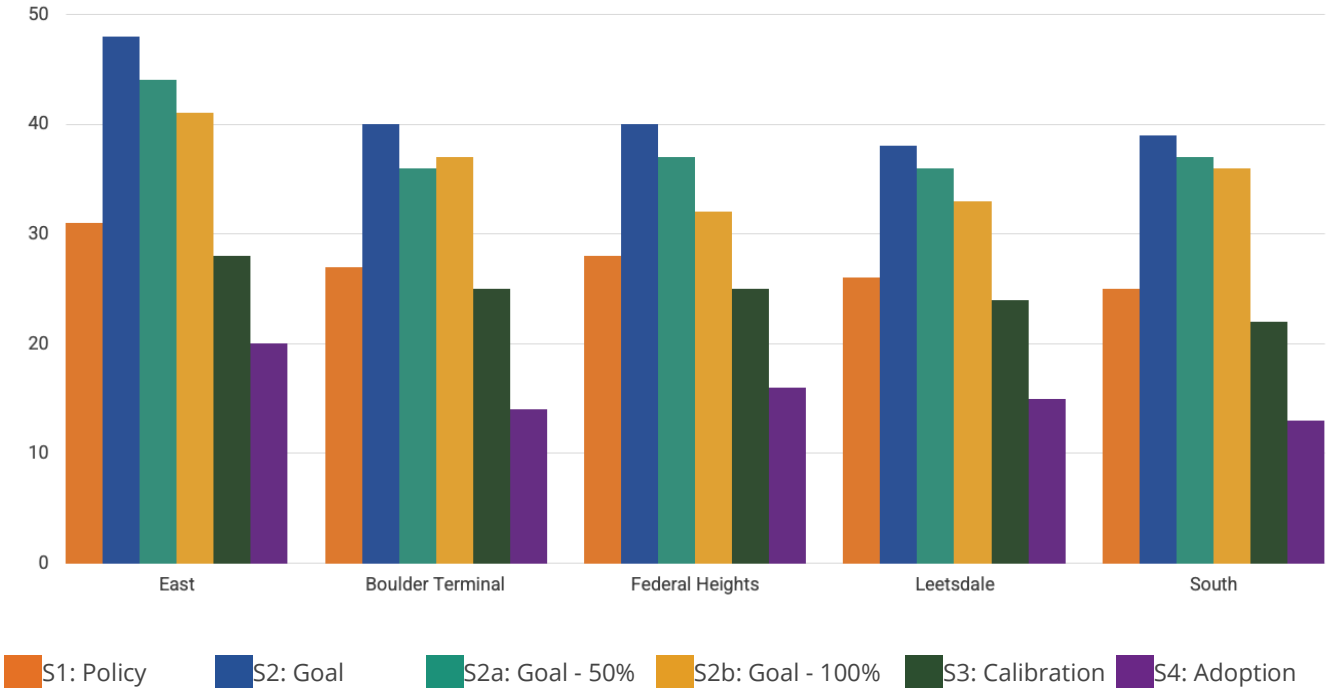
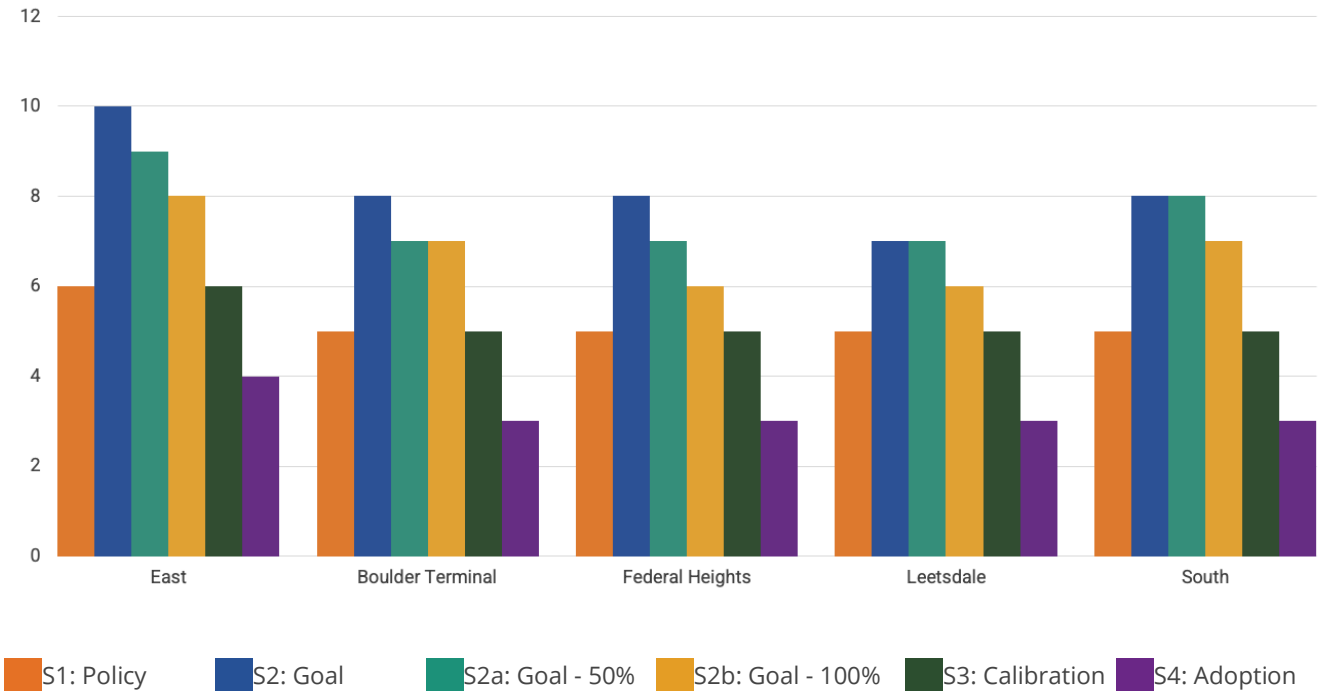


Figure 9: Count of new transformer banks required for the top five substations by 2050 (Source: Kevala)



4. Conclusions and Areas of Future Study

As previously noted, this study integrated all geospatial network infrastructure, customer usage, rate, and program data available at the time of this study to develop a base load and future DER scenario forecast and grid analyses. As additional AMI, customer adoption, and behavior data become available, it will inform even more precise insights into the distribution grid impacts of electrification across PSCo's diverse service territory. While this report is designed to summarize the methodology and results of this study, there are a few recommendations for future electrification impact analyses:

- Conduct the study using at least one year of historical customer AMI interval data. Kevala was able to leverage interval data for large customers at the time of this study to develop base load shapes for each large customer premise, using machine learning to complement the data available. Load shapes would be even better informed by a full year of historical customer AMI interval data once available. That said, this analysis continues to demonstrate that a bottom-up forecast can be achieved without a full set of AMI data, which was also demonstrated in the U.S. Department of Energy's Transportation Electrification Impact Study.[25]
- Develop more granular scenarios that incorporate any community-specific DER technology adoption scenarios in order to assess grid impacts and mitigations of community or city-specific policies. Kevala and PSCo had a number of conversations with specific municipalities served by PSCo during the design phase of this study (e.g., Denver and Boulder); while these conversations were productive in terms of understanding priorities for these municipalities, they did not produce quantitative data to inform this study's modeling approach. To reflect stronger incentives in Denver and Boulder, Kevala developed adoption propensity weights for certain technologies (see Appendix K and Appendix L for additional information) in earlier forecast years; these weights could be updated and extended to reflect additional assumptions on a more granular basis in the future.
- Consider running scenarios with varying weather conditions. All scenarios in this EIM were run with extreme cold winter weather. If the same scenarios and targets were run with extreme summer weather or a combination of extreme winter and summer weather,

[25] The Transportation Electrification Impact Study used a similar approach to this bottom-up forecast. The addition of calibrating to customer monthly bills and use of customer monthly bill levels to further refine the NREL load shapes is a noted improvement over that study.
NREL, Lawrence Berkeley National Laboratory, Kevala Inc., and U.S. Department of Energy, *Multi-State Transportation Electrification Impact Study: Preparing the Grid for Light-, Medium-, and Heavy-Duty Electric Vehicles*, DOE/EE-2818, U.S. Department of Energy, 2024, https://www.energy.gov/sites/default/files/2024-03/2024.03.18%20NREL%20LBNL%20Kevala%20DOE%20Multi-State%20Transportation%20Electrification%20Impact%20Study%20FINAL%20DOCKET.pdf

resulting system net loads would provide insight on assets requiring additional infrastructure or "hot spots" where feeders are frequently overloaded.

- Train certain specific demand modifier methodologies on DER-specific data from PSCo's service territory, as available. For example:
    - CSG: Consider new feeders built in areas that would be eligible for adoption in later forecast years.
    - DR: Consider events triggered on distribution-level localized peaks instead of at the system-level peak.[26]
    - EV/EVSE: Ingest and incorporate EVSE interconnection data from PSCo to further explore customer behavior and operational temperature sensitivity.
- Incorporate known projects by PSCo into the upgrade methodology to ensure design alignment with future known projects. Kevala identified new asset needs based on point-in-time overloads without acknowledgement of future projects already slated for construction by PSCo. Ensuring these two design approaches to the grid would provide additional insight as to whether planned projects are timed appropriately or need to be delayed/moved to start earlier where possible.

As demand modifiers continue to impact the amount of load required, understanding their impact continues to become paramount. Tracking where and when, at a premise level, a demand modifier is adopted corresponds to a shift in the energy demand at that specific location. Using this bottom-up approach to load forecasting allows for more in-depth grid planning on a feeder-level basis.

[26] Note that, while simulating new operational programs to curtail local peaks may be relatively straightforward, implementation may require new analysis, personnel, and/or technology deployment to be successful, all of which have either fixed or variable costs associated with them.

Appendix A. Data Ingestion and Mapping

A.1 Study Data

Kevala's Electrification Impacts Model (EIM) requires several sources of data and varies depending on the availability and quality of data and the time permitted to perform the analysis. Typically, a study using the EIM includes some or all of the following data:

- Grid topology and mapping
- Existing asset characteristics (rating, voltage, feeder length, etc.)
- Advanced metering infrastructure (AMI)
- Supervisory control and data acquisition (SCADA)
- Historical and/or forecasted weather
- Rate schedules or customer class designation for premises
- Historical billing data
- Census data
- Customer information, such as participation in utility programs
- Interconnection data for solar photovoltaics (PV) or battery energy storage systems (BESS)
- Electric vehicle (EV) adoption or existing EV service equipment (EVSE) installations
- Standard asset characteristics and costs (such as rating or voltage) for typical units

For this study, Kevala used the following data provided by Public Service Company of Colorado (PSCo):

- AMI data for large customers[27]
- Geographic information system (GIS) data
- Estimates of project costs for typical capacity expansion projects
- Build logic guidelines for capacity expansion projects, including system limitations and mitigation strategies
- Synergi customer data
- Equipment and asset characteristics
- Asset spatial data and hierarchical relationships
- Electric and gas customer bills
- Sample EV load shapes based on PSCo's historical customer base
- Existing PV interconnection data and associated characteristics by premise
- PSCo 30-year distributed energy resource (DER) targets
- PSCo bulk energy and peak capacity forecasts, as reflected in PSCo's Distribution System Plan (DSP) filed in 2024

[27] AMI data was not available for the entire service territory.

- Customer revenue classes
- Dense urban, urban, and rural county designations, including substation categorization

Additionally, Kevala used the following publicly available data or proprietary data from the Kevala platform:

- Climate model data from National Renewable Energy Laboratory's (NREL's) Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC) dataset[28]
- NREL's PVWatts Calculator[29]
- Lawrence Berkeley National Laboratory's Tracking the Sun dataset[30]
- NREL's National Solar Radiation Database (NSRDB)[31]
- National Renewable Energy Laboratory's (NREL's) ResStock[32] and ComStock[33] data
- Bureau of Transportation Statistics' Local Area Transportation Characteristics for Households (LATCH Survey)[34]
- Distribution of EE savings from Kevala's proprietary database

A.2 Data Ingestion

Kevala ingested, mapped, and analyzed the data received and designed and implemented an overall data structure for the distribution system that allows for premise-level analytics that can be aggregated to service transformers, feeders, substation transformer banks, substations, and up to the full service territory. The total number of each of these assets included in the study is shown in Figure A-1.

[28] NREL, "Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC)," accessed through the Open Energy Data Initiative (OEDI), dataset last updated September 22, 2023, https://dx.doi.org/10.25984/1970814

[29] NREL, PVWatts Calculator, https://pvwatts.nrel.gov/

[30] Lawrence Berkeley National Laboratory, Tracking the Sun, 2023 edition, https://emp.lbl.gov/tracking-the-sun

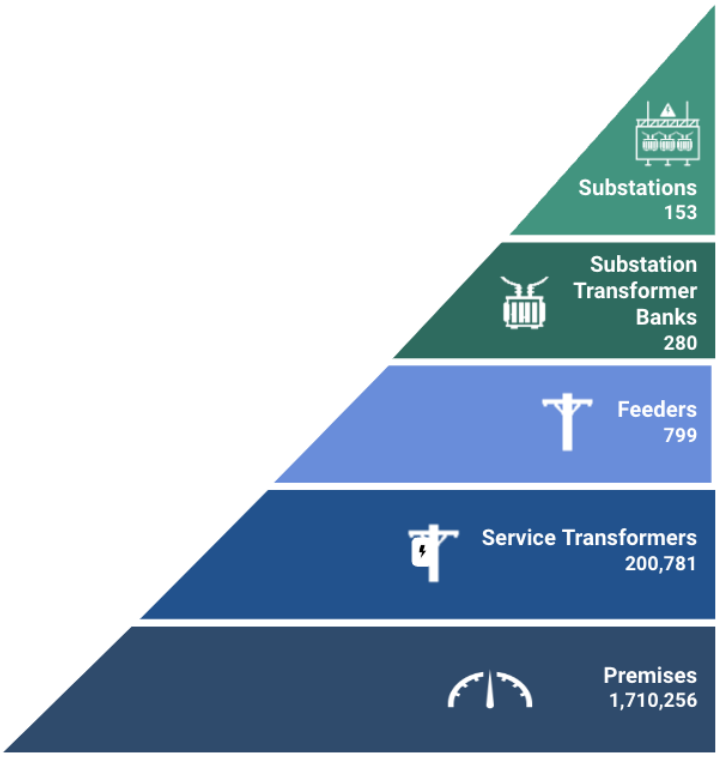
[31] NREL, "NSRDB: National Solar Radiation Database," 2018-2022 Actual Meteorological Year data, https://nsrdb.nrel.gov/

[32] NREL, "ResStock: Highly granular modeling of the U.S. housing stock," 2022, Release 1.1, https://resstock.nrel.gov/

[33] NREL, "ComStock: Highly granular modeling of the U.S. commercial building stock," 2023, Release 2, https://comstock.nrel.gov/

[34] U.S. Department of Transportation, Bureau of Transportation Statistics, "Local Area Transportation Characteristics for Households (LATCH Survey)," February 2021, https://www.bts.gov/latch

Figure A-1: Number of PSCo's grid assets mapped for the study (Source: Kevala)



A.3 Data Mapping

The data collected was mapped together to enable proper aggregation of premise-specific data to grid infrastructure and linking known DERs to the grid. The GIS geospatial and hierarchy diagrams provided by PSCo were critical to associating the consumption of a meter to the electrical infrastructure via a many-to-one match to a premise (i.e., many meters were associated to a premise).

Customers and their meters were associated with an account ID, revenue class, and premise. Premises were related with GIS mapping to a parcel, service transformer, and feeder. Feeders were mapped to substation transformer banks within a substation. The premise-level load, aggregated up to each distribution grid component, provided the information Kevala needed to assess load and DER growth impacts on different parts of the distribution grid (see Appendix D).

Due to data limitations, 16,321 premises could not be mapped to a distribution asset and were excluded from this study. The total 2024 forecasted non-coincident peak of these service points was approximately 190 MW and total energy was 560 GWh.

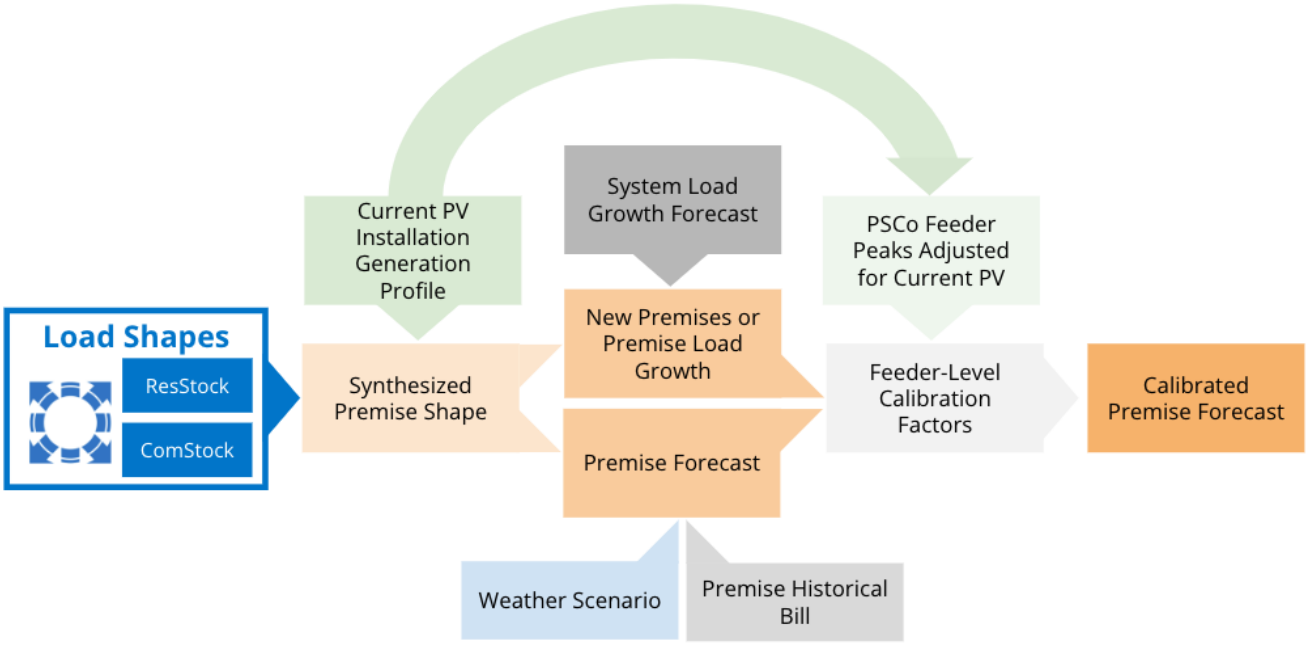
Appendix B. Base Load and Customer Load Growth Methodology and Additional Results

B.1 Approach

Base load profiles represent the underlying energy use at a premise given the current state of energy-consuming technologies on the premise, excluding known photovoltaic (PV) systems. That is, it reflects the expected energy consumption given installed energy efficiency (EE) technologies, heating and cooling equipment, appliances (including water heating), lighting, and other energy-consuming processing, particularly for industrial or commercial properties. As a result, base load is a function of historical customer behaviors and weather. It is important to note that, with the exception of PV systems, knowledge of whether a premise has existing distributed energy resources (DERs) installed is difficult to obtain, so there may be other DER technologies installed at the premise.

Base load forecasts are a bottom-up projection of the energy consumption at the premise prior to any incremental DERs and existing PV installations over a long time horizon. Because these forecasts are trained to include the effects of weather on loads, they can also consider the impact of future climate projections on energy consumption. The weather inputs used for this study are discussed further below. Base load also reflects the addition of load growth due to new premises or the expansion of operations at an existing premise. Figure B-1 shows the flow of the base load and load growth modeling.

Figure B-1: Base load and load growth modeling approach (Source: Kevala)



For this study, the base load forecast methodology included several steps, including developing simulated advanced metering infrastructure (AMI) data:[35]

1. **Modeled hourly PV generation:** For each service point with existing PV, Kevala modeled the hourly generation using the PV behavior modeling explained in Appendix C with the size of the system defined by PSCo interconnection data and 2018 irradiance data.
2. **Estimated annual base load demand:** Using 2023 customer billing data, Kevala estimated base load for each service point by taking the annual energy (kWh) from the customer bills and adding the total PV generation estimated in step 1. For customers with missing monthly bill values, Kevala imputed values[36] by first taking the previous month's bill, or if not available, the following month's bill. If neither were available, Kevala took the mean bill from the months available.
3. **Identified load shapes:** To determine load shapes by premise, Kevala employed different techniques by class:
    a. Residential and commercial: The National Renewable Energy Laboratory's (NREL's) End Use Load Profile dataset[37] for residential (ResStock) and commercial (ComStock) buildings contains 15-minute end use disaggregated load shapes. Kevala used these load shapes as a proxy for the net load of a premise (i.e., AMI data). The process included assigning a premise to an NREL geographic area, choosing one of the available residential or commercial load shapes to use for the premise, and scaling the load shape by the number of units for residential and square feet of floor area for commercial. Kevala used revenue class, state/county, gas billing data, and annual energy demand to match reference buildings to premises.
    b. Industrial: The NREL load shapes do not have estimated load shapes for industrial customers. Therefore, Kevala assumed a flat load shape with no weather dependencies for just over 100 large industrial customer premises. Kevala also used flat load shapes for premises with unknown revenue classes.
4. **Calibrated load shapes:** Kevala used the estimated annual base load demand generated in step 2 to scale the hourly NREL load shapes such that each month's energy consumption matches the monthly energy consumption from the billing data.
5. **Adjusted for large customers:** Kevala received actual hourly data for 17 large commercial customers and replaced the simulated load data with this real measured data from PSCo.

[35] AMI data was not available for the entire service territory.
[36] The billing data is generally of high quality; however, roughly one-third of service points were missing one or more months in the dataset.
[37] Wilson et al., End-Use Load Profiles for the U.S. Building Stock: Methodology and Results of Model Calibration, Validation, and Uncertainty Quantification, NREL/TP-5500-80889, 2022. https://www.nrel.gov/docs/fy22osti/80889.pdf

6. **Generated hourly base load forecast for all premises:** The base load forecast was developed using a tree-based regression model trained on the simulated AMI data created in steps 1-4 as well as climate data to model gross demand given future weather scenarios from climate model projections. The base load forecast model generated a forecast of hourly energy use at each premise that reflects weather conditions prior to any incremental DERs using an extreme cold winter weather scenario based on the NREL Sup3rCC dataset for all forecast years.[38]
7. **Forecast load growth:** Kevala calculated load growth from the year-over-year percent change in net energy forecast, which was then applied to the base load forecast on gross energy. The load growth model created new residential premises and increased the demand of commercial and industrial (C&I) premises according to PSCo's system load forecast, as represented in the Distribution System Plan (DSP). Residential load growth was implemented as an estimate of new premises to meet the system residential load growth estimate. For new residential premises, Kevala modeled the load based on the load characteristics of other residential customers in the area. C&I load growth was applied as a simple year-over-year percent growth for already established C&I loads.
8. **Calibrated peaks:** The last step to generate the base load forecast was to calibrate the peak demand to PSCo's 2024 planning peaks by feeder. PSCo generates peak forecasts for each feeder based on historical supervisory control and data acquisition (SCADA) data that is cleaned and weather normalized. The weather-normalized SCADA data is then adjusted for a severe weather forecast, much like Kevala's base load forecast executed in step 7. This forecast includes all behind-the-meter DERs installed, including PV.

   To ensure the base load forecast was calibrated to the observed peak data, Kevala created calibration factors. First, for each feeder, Kevala estimated the peak load at the feeder head by aggregating the base load forecasts by feeder, applying losses of 5.855% to scale load at the feeder head, and adding the existing PV from step 2 (also scaled for losses).[39] The calibration factor was then estimated as the ratio of PSCo's DSP peak load for 2024 to Kevala's peak load at the feeder head. Finally, Kevala applied the calibration factor to the premise-level base load forecasts to maintain consistency at different levels of aggregation.

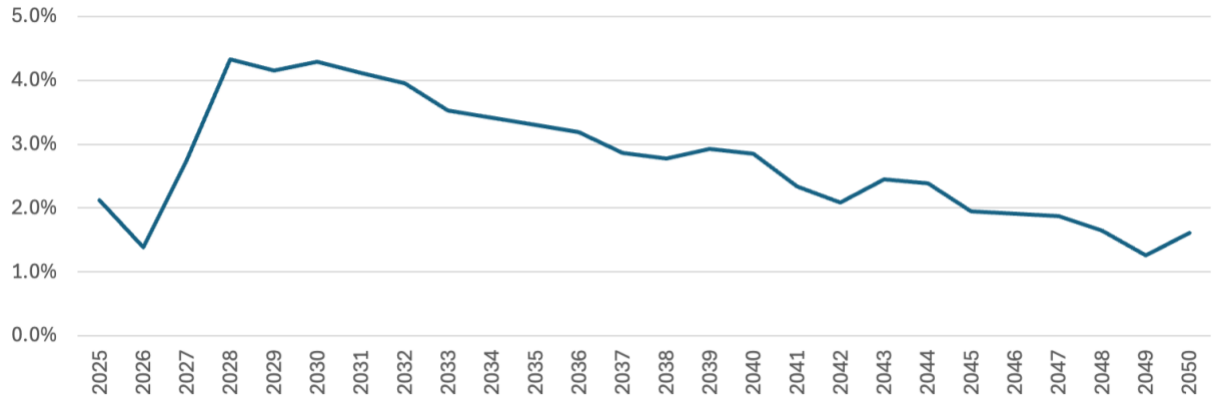
[38] NREL, "Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC)," accessed through the Open Energy Data Initiative (OEDI), dataset last updated September 22, 2023, https://dx.doi.org/10.25984/1970814

[39] PV systems were assumed to both export energy to the grid and offset energy use at the premise. Kevala applied losses assuming a reverse flow, multiplying the hourly generation by 1-0.05855 and dividing base load by 1-0.05855. This may result in slightly higher load at the feeder head if the PV generated is actually offsetting load. Kevala corrected for this in the use of the calibration factors developed in step 8 for each feeder.

The following are the key assumptions associated with base load and customer load growth modeling:

- Distribution losses were estimated as 5.855%.
- Only PV was disaggregated from the base load forecasts, meaning there may be existing demand modifiers at a premise that are not captured in this study. For example, the forecast may select a premise to adopt a DER, such as EVSE, that may already have adopted that DER previous to 2024. Given the relatively lower adoption levels of DERs besides PV, the impact of this is expected to be minimal.
- Kevala used PSCo's DSP forecast of load growth in its base load forecast. Figure B-2 shows PSCo's percentage of cumulative load growth of all customers on the distribution system. There is a significant percent growth through 2028, and then growth steadily declines thereafter.

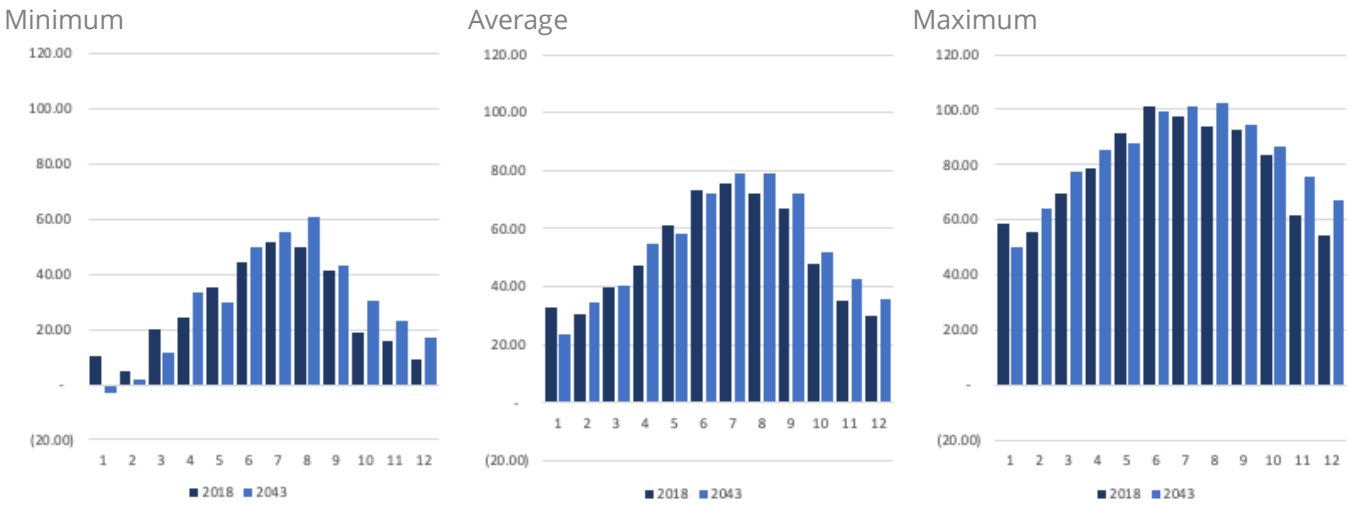
Figure B-2: Percent load growth used in Kevala's base load forecast: 2025-2050 (Sources: PSCo, Kevala)



- As noted above, due to data limitations, Kevala was not able to map about 17,000 premises to the grid. These premises were used in calibrating load to PSCo's annual forecast but not in the feeder calibration. Kevala assumed the feeder calibration corrects for these missing premises.
- Models were trained on weather data from 2018, and the forecast was based on weather data from 2043, which reflects an extreme cold winter weather scenario. Figure B-3 shows the minimum, average, and maximum temperatures between 2018 and 2043 by month. The minimum temperatures show much lower temperatures for 2043 and, coincidently, the summer minimums are also much higher. This pattern continues for average temperature while the maximum temperatures show 2043 being higher but not as dramatically as with 2018.
- The NREL dataset uses weather year 2018, so Kevala scaled the simulated data using the 2023 billing data provided by PSCo. This means that variability in the 2023 hourly load

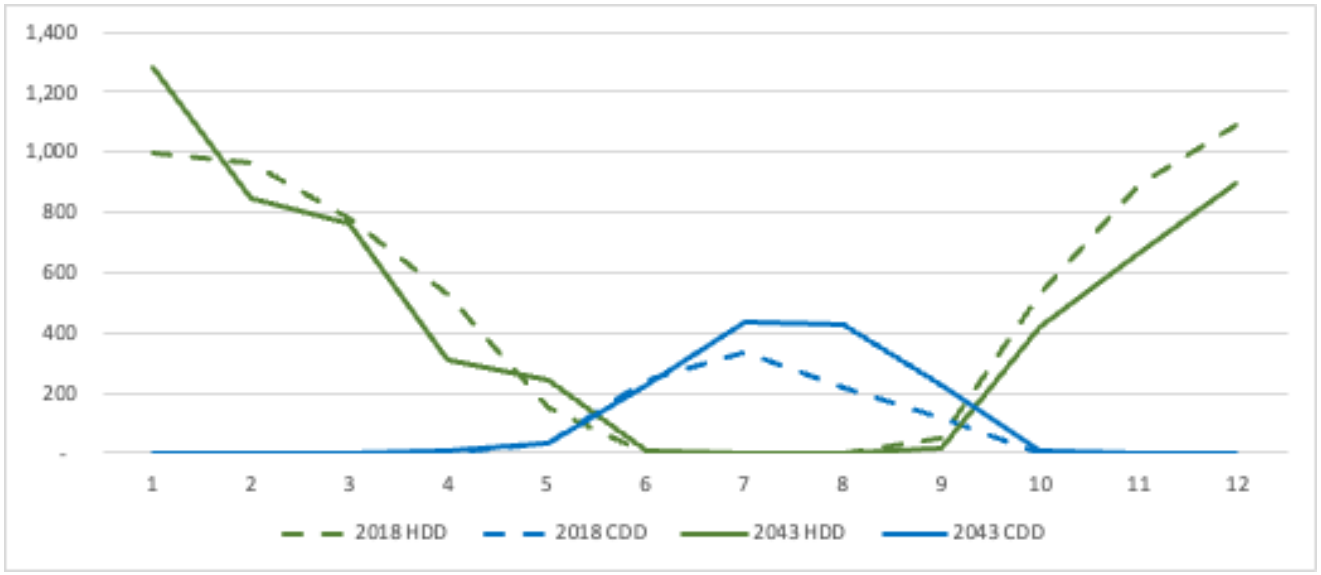
profile correlates to 2018 weather while the monthly total energy use correlates to 2023 billing data.

Figure B-3: Minimum, average, and maximum temperatures (°F) between 2018 and 2043 by month (Source: Kevala analysis of NREL Sup3rCC data)



Examining the heating degree days (HDDs)[40] and cooling degree days (CDDs)[41] in Figure B-4 shows that the number of HDDs is higher in January in 2043, but 2018 is higher in all other months. Further, the 2043 CDDs are much higher than 2018.

Figure B-4: HDD and CDD comparisons (using the cumulative delta) between 2018 and 2043 weather data (Source: Kevala)



[40] HDDs are estimated as the positive difference between the average daily temperature and 65°F.
[41] CDDs are estimated as the positive difference between the average daily temperature and 65°F.

Note: The y-axis of the chart is the annual sum of the difference in average daily temperature and a base temperature of 65°F.

B.2 Analysis and Results

All scenarios used the same base load forecast, which included load growth. Figure B-5 shows the cumulative system peak base load (GW) and total energy (TWh); it shows about 1% compound annual growth rate (CAGR) but also reflects the declining percent load growth from PSCo's load forecast. As shown in Figure B-2, PSCo's load growth target (as a percent of overall year-on-year system load) ramps in initial forecast years, and settles out to between 1 and 2% by the end of the study period, which is similarly reflected in Figure B-5.

Figure B-5: Base load system peak demand (GW) and cumulative energy (TWh), 2024-2050 (Source: Kevala)

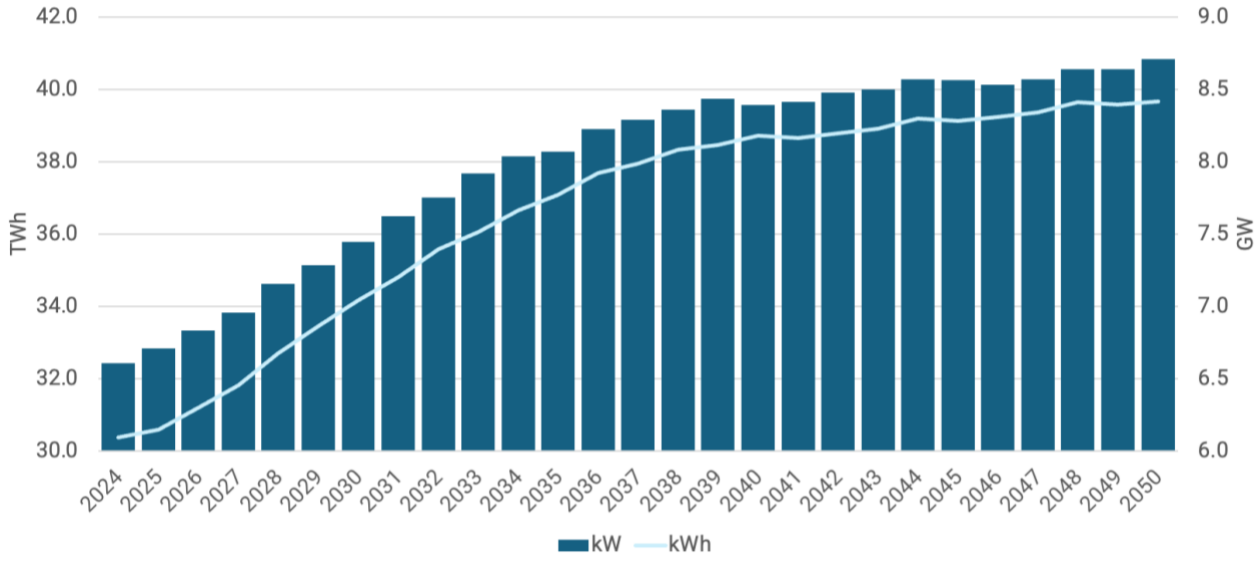
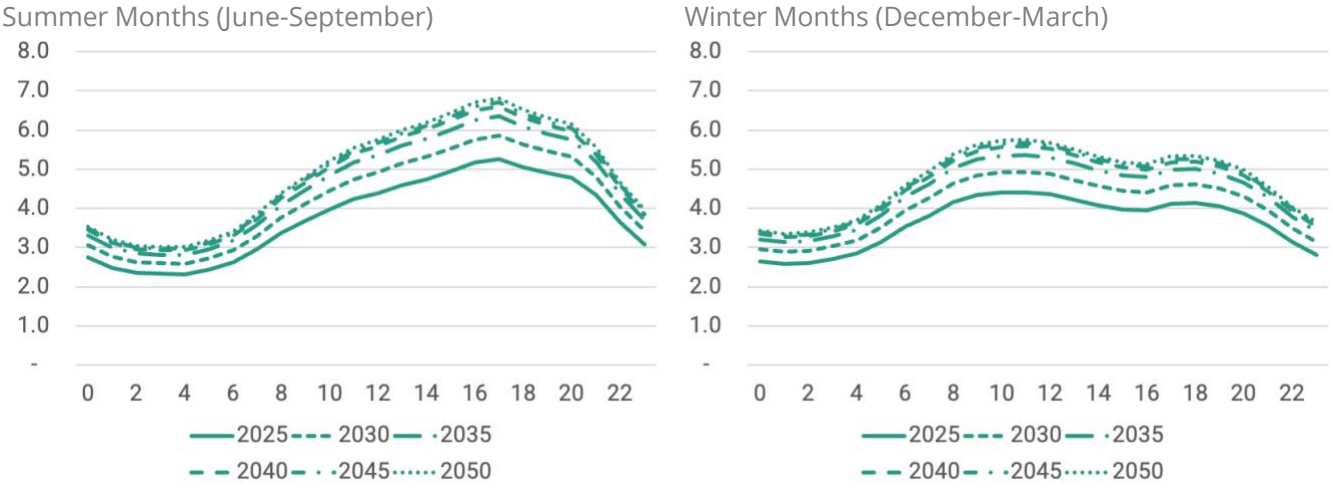


Figure B-6 shows the average base load shape by season (winter and summer). Base load is generally lower in the winter with a double peak—the morning system peak between 0800 and 1100 and the evening peak from 1700 and 2000. The summer peak is more prominent between 1500 and 1800. Because these load shapes exclude new DERs and existing PV, the charts show more traditional shapes. Finally, as expected, load growth is reflected with the levels of the shapes changing, but the shapes remain constant over the years.

Figure B-6: Base load shape (GWh) on system peak day by season: 2025-2050 (Source: Kevala)



The following are key findings from Kevala's analysis of the base load results:

- The coincident peak hour from the simulated AMI data occurs in September, while historically the coincident peak has occurred in July. This is driven by the NREL load shapes, which are based on 2018 weather. While the timing (when it occurs) of the peak deviates from that of PSCo's forecasts, this is less relevant to peak planning as long as the size of the peak is correctly reflected. Given Kevala calibrated to PSCo's peak forecast, this issue is mitigated.
- This analysis continues to demonstrate that a bottom-up forecast can be achieved without a full set of AMI data, which was also demonstrated in the U.S. Department of Energy's Transportation Electrification Impact Study.[42] The use of actual AMI data would improve the bottom-up forecast and should be targeted for future work. Nevertheless, the value of a bottom-up forecast approach is demonstrated with this study.

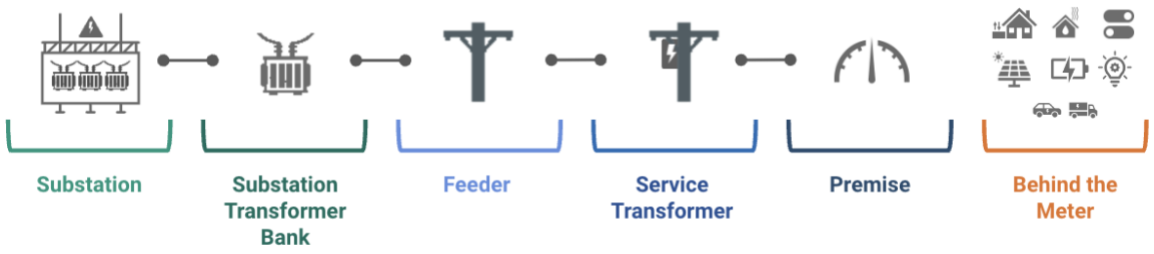
[42] The Transportation Electrification Impact Study used a similar approach to this bottom-up forecast. The addition of calibrating to customer monthly bills and use of customer monthly bill levels to further refine the NREL load shapes is a noted improvement over that study.
NREL, Lawrence Berkeley National Laboratory, Kevala Inc., and U.S. Department of Energy, *Multi-State Transportation Electrification Impact Study: Preparing the Grid for Light-, Medium-, and Heavy-Duty Electric Vehicles*, DOE/EE-2818, U.S. Department of Energy, 2024, https://www.energy.gov/sites/default/files/2024-03/2024.03.18%20NREL%20LBNL%20Kevala%20DOE%20Multi-State%20Transportation%20Electrification%20Impact%20Study%20FINAL%20DOCKET.pdf

Appendix C. Net Load Modeling Methodology and Additional Results

C.1 Approach

Figure C-1 shows a simplified grid diagram depicting grid infrastructure assets and their connectivity as used for this study. From left to right, a transmission line feeds a substation that typically has between two and three substation transformer banks; each substation transformer bank serves between two and seven feeders to distribute power to neighborhoods. The feeders can each serve up to thousands of customers via primary lines or line segments that, with the help of service transformers, distribute the power to the premises.

Figure C-1: Grid infrastructure connectivity diagram of substations, substation transformer bank groups, substation transformer banks, feeders, and service transformers that distribute electric power to premises via the distribution grid (Source: Kevala)



Kevala determined the net load (base load plus demand modifiers) at each distribution system asset for each year of the 2024-2050 study period. System coincident peaks and substation non-coincident peaks were determined from the net load. Each demand modifier's contribution (generation or consumption) was quantified at the system coincident peak day and hour to show its contribution to the system peak as well as local distribution peaks that are often noncoincident with the system peak.

C.2 Analysis and Results

System peak load shifts from summer in the early forecast years to a winter peak, with the highest net load in January and February for all scenarios starting in 2031 (see Figure C-2). Winter peaking on the system is driven by the increased adoption of electric heat pump water heaters (HPWH) and heat pump heating, ventilation, and air conditioning (HP HVAC) systems. These units would see additional use during colder months coupled with reduced PV generation as the system peak migrates into the winter months when sunlight is weaker.

Figure C-2: Percentage of system net load peak days by season and scenario: 2025-2050 (Source: Kevala)

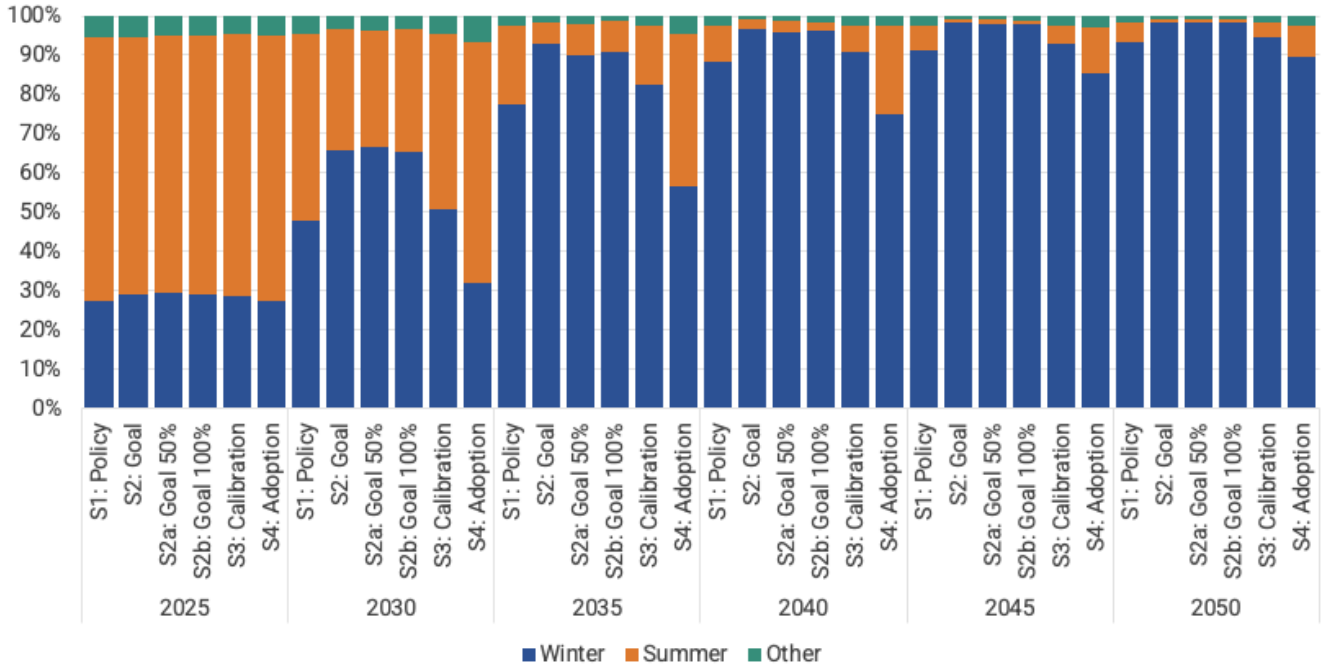
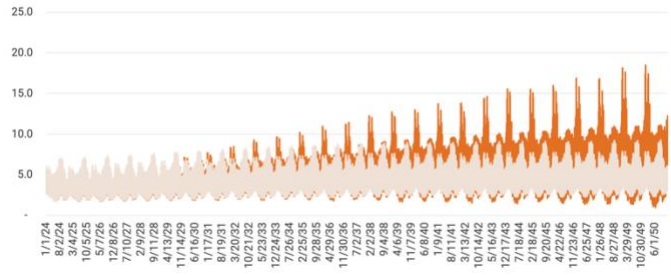


Figure C-3 shows an overlay of base load across all years on top of net load curves for each scenario. Base load remained consistent across all the scenarios. Net load growth is highest in Scenarios 2, 2a, and 2b as expected as those are the scenarios with the highest demand modifier adoption targets.

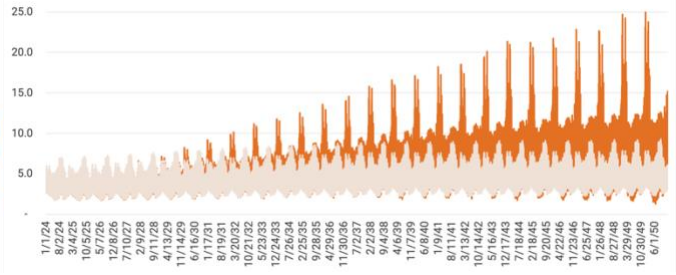
Scenario 4 showed modest system net load growth compared to its base load. Without high adoptions on the system, the net load remains comparable to the base load growth.

Figure C-3: Hourly base (light orange) and net load (dark orange) curves for the distribution system (GW): 2024-2050 (Source: Kevala)

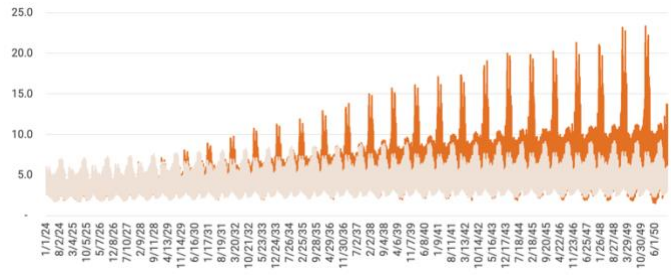
Scenario 1: Policy Aligned



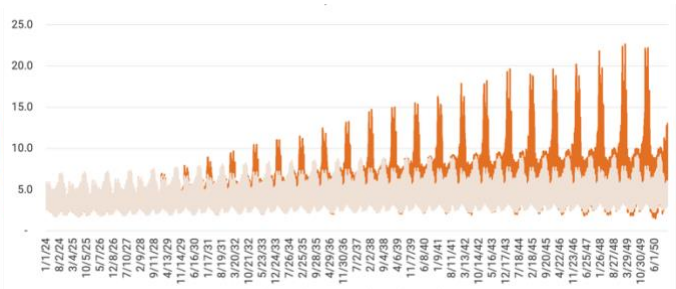
Scenario 2: Goal Aligned



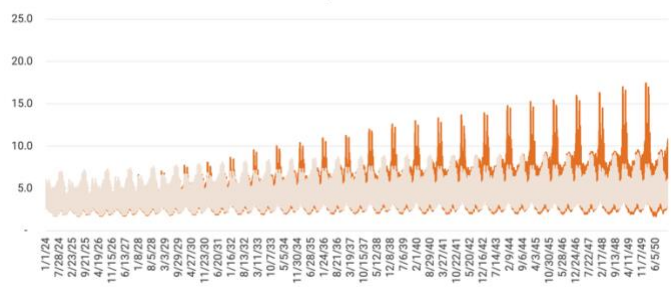
Scenario 2a: Goal Aligned, Mitigation A (50%)



Scenario 2b: Goal Aligned, Mitigation B (100%)



Scenario 3: Calibration



Scenario 4: Adoption Trajectory

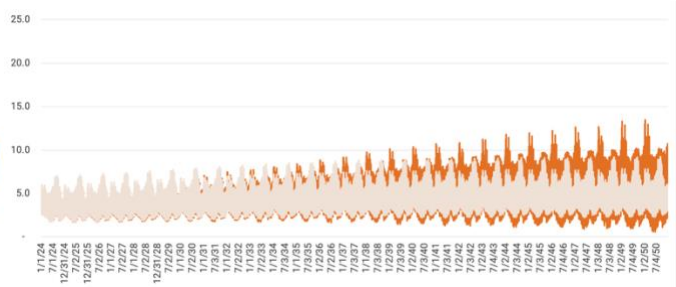
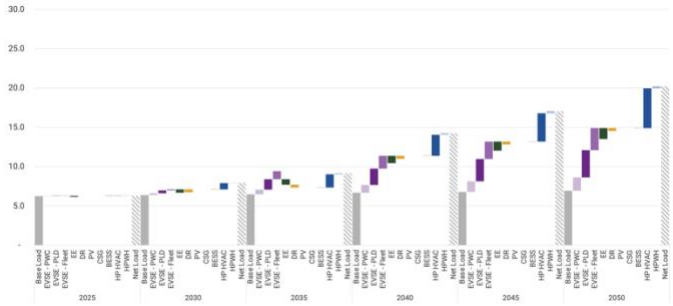


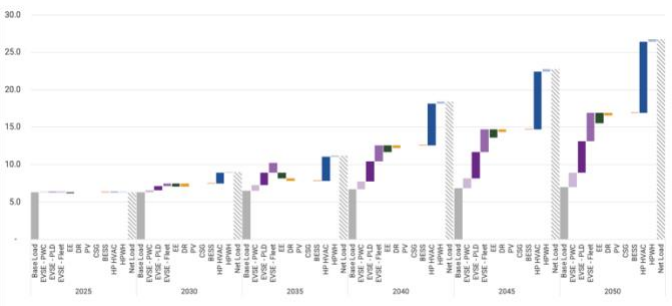
Figure C-4 shows each scenario's system peak day's peak hour and the corresponding demand modifier contributions to the overall net load at that hour. The charts are all shown on the same y-axis scale for relativity and comparisons. The impact of EVSE and heat pumps on net load is visualized with longer bars increasing the overall net load. As the system shifts to a winter peak, the ability of solar generation to offset load is diminished due to more limited solar irradiance during the winter months and coldest hours.

Figure C-4: DER contribution to system peak day, peak hour load (GW) by scenario and year: 2025-2050 (Source: Kevala)

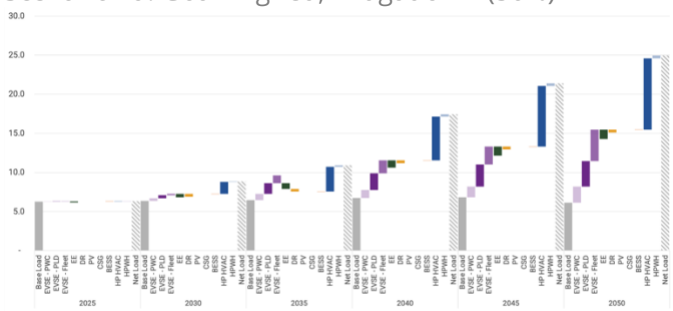
Scenario 1: Policy Aligned



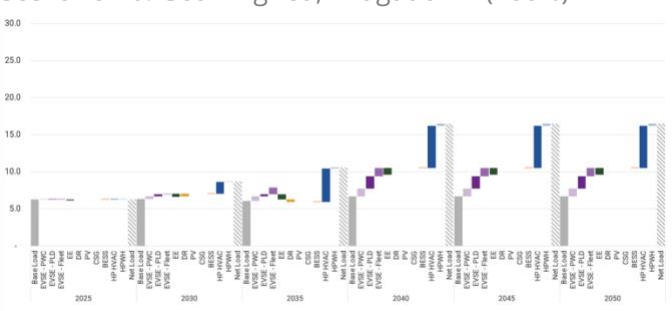
Scenario 2: Goal Aligned



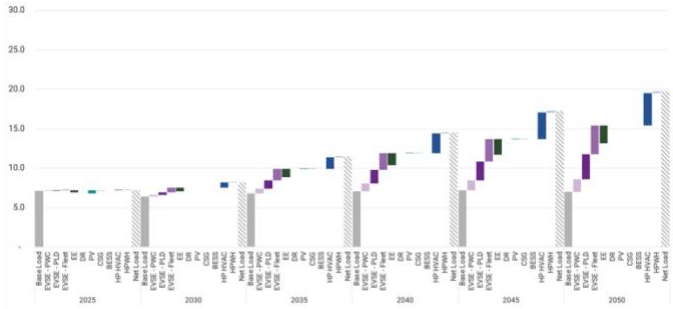
Scenario 2a: Goal Aligned, Mitigation A (50%)



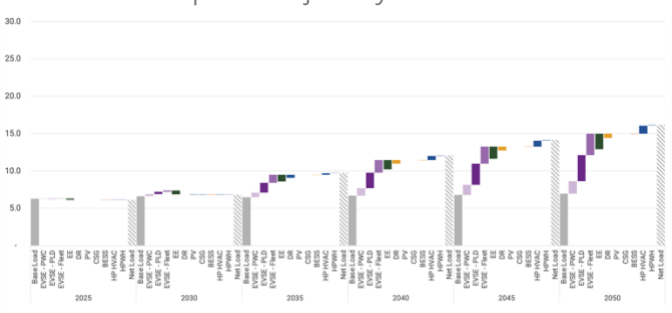
Scenario 2b: Goal Aligned, Mitigation B (100%)



Scenario 3: Calibration



Scenario 4: Adoption Trajectory



Base Load | EVSE-PWC | EVSE - Pers. | EVSE-Fleet | EE | DR | BTM PV | CSG | BESS | HP HVAC | HPWH | Net Load

Scenario 1 system peak days and corresponding net loads are shown in Figure C-5. All charts for this scenario are on the same scale to show changes in contribution across the years. The days listed in the chart titles are the system coincident peak days for each year.

For Scenario 1, the Policy Aligned scenario, the contribution from DERs is smaller than in other scenarios. When the coincident peak day shifts to early January, the influence of heat pumps becomes more pronounced. Winter peak days reduce the generation impact of solar with weaker sunlight for generation.

The system peak hour shifted from early evening to later in the evening as the use of HP HVAC systems increased. Fleet charging also increased in the evening hours, continuing into the late night. This increase reflected the expected load shape of the fleet charging.

Figure C-5: Total peak system day load and DER impacts (GW) by year, Scenario 1, Policy Aligned: 2025-2050 (Source: Kevala)

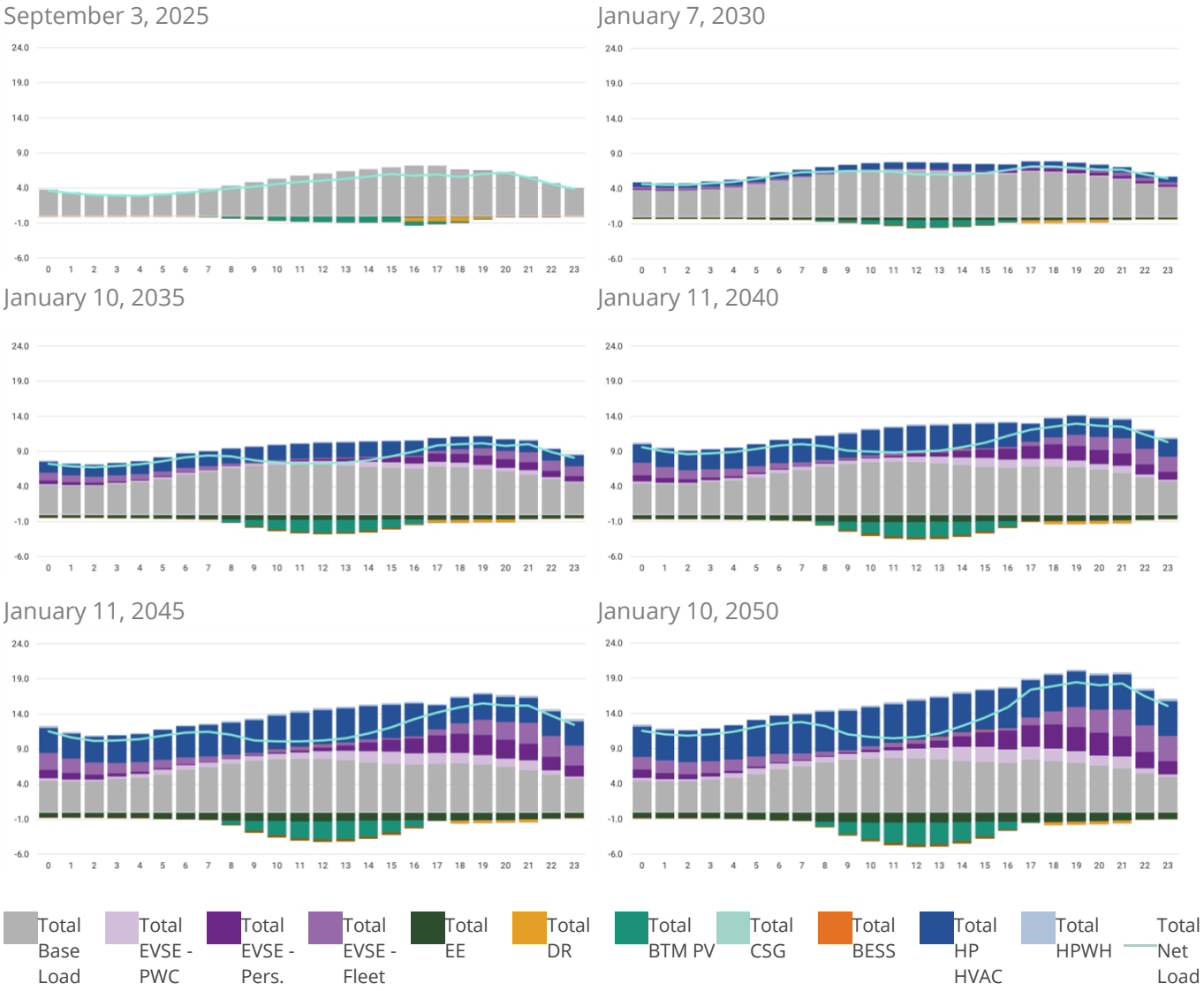
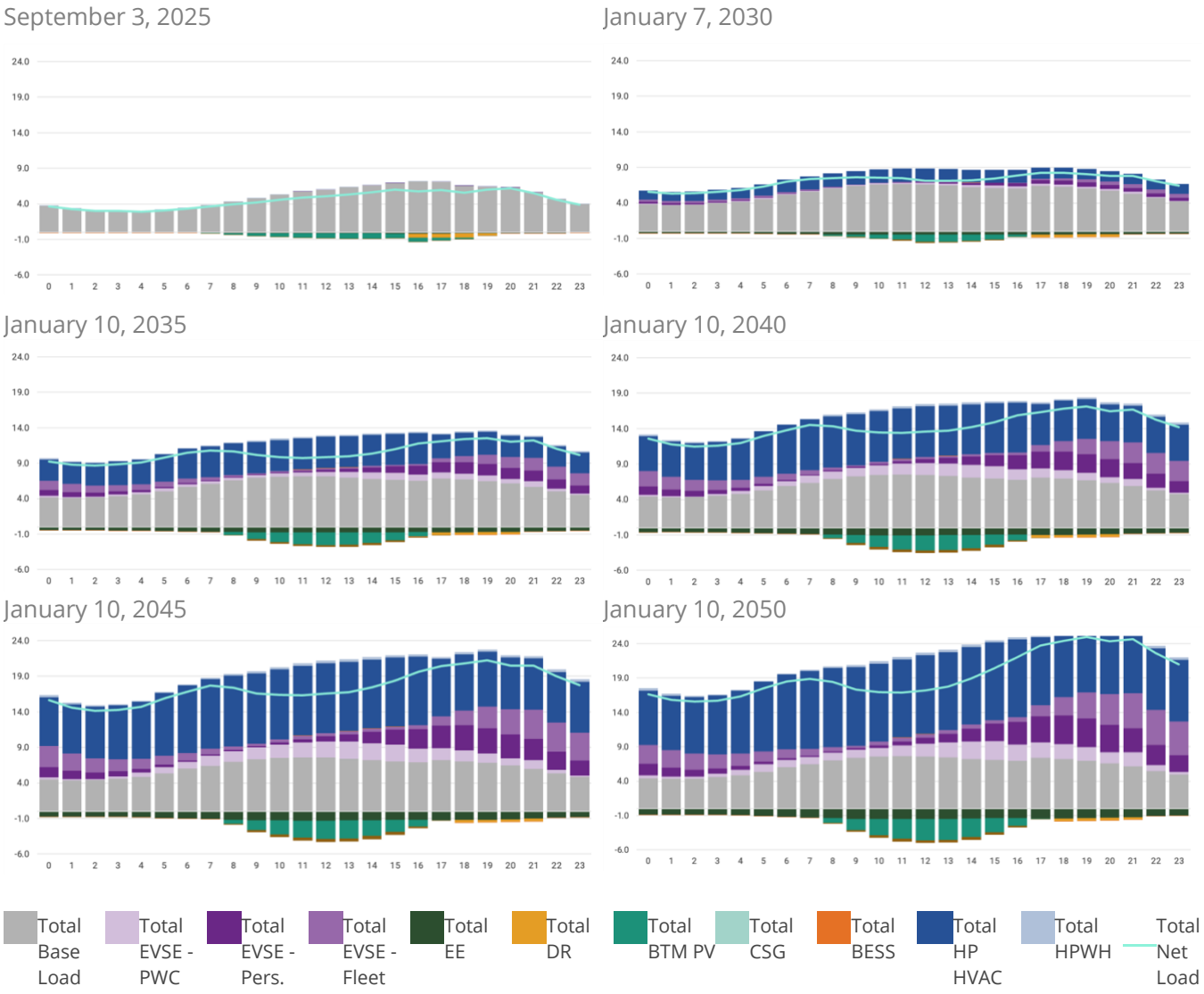


Figure C-6 shows the system coincident peak day load and contribution by each demand modifier for Scenario 2 for 2025-2050. All charts are on the same scale to show changes in contribution across the years. The days listed in the chart titles are the system coincident peak days for each year. Scenario 2, the Goal Aligned scenario, reflects the greatest DER adoptions of the scenarios. As HP HVAC adoptions increase, segment-specific demand impacts become more pronounced. The peak hour of the system peak day is toward the late evening hour (approximately 1900), when HP HVAC and EV charging is typically the highest, particularly in later forecast years.

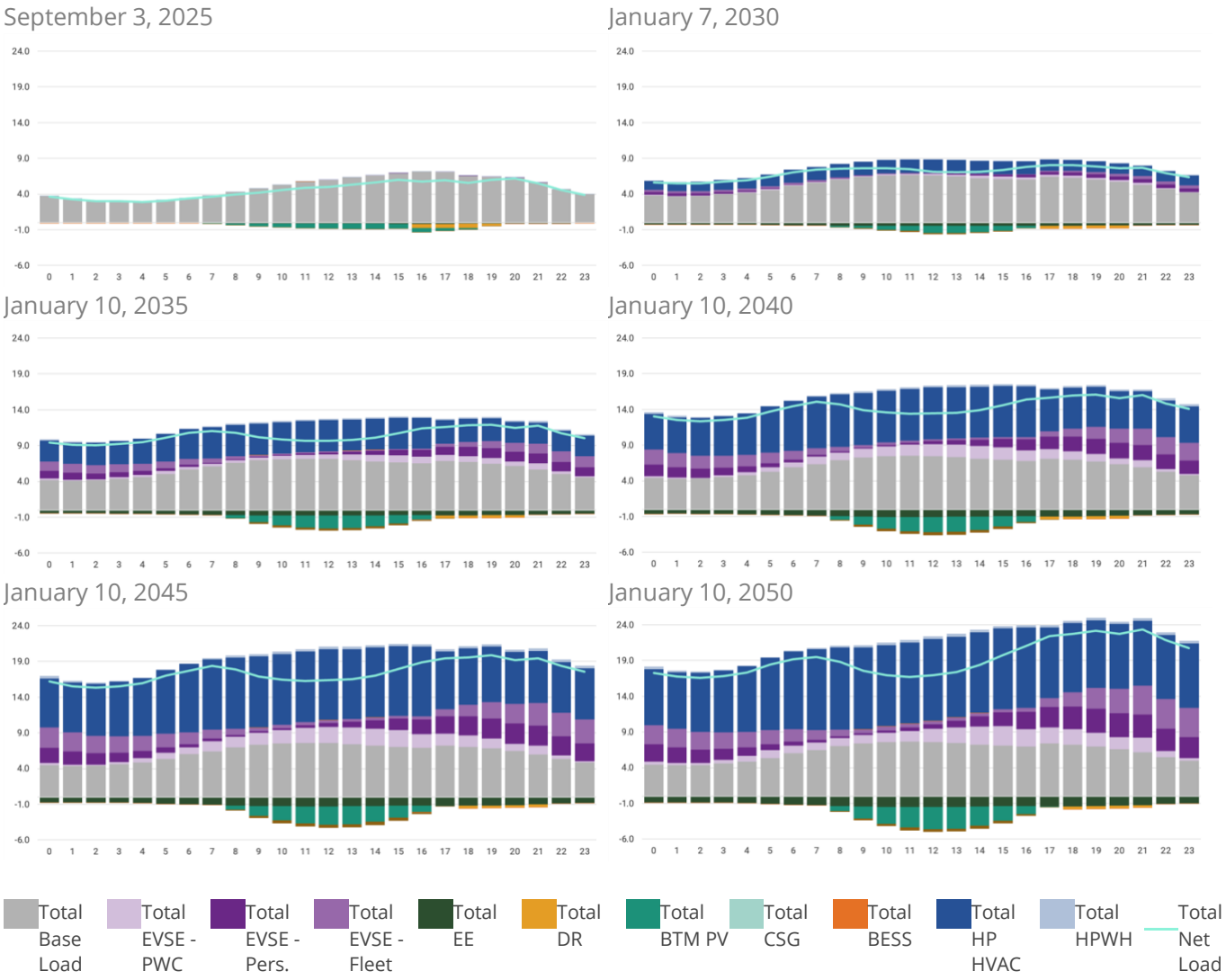
As winter system peak days emerge in January 2030, the increased contribution of heating elements to overall net load is anticipated because these units are run more consistently during the evening hours when residents are in their homes and their personal light duty or fleet vehicles have returned to their home charging stations for the night. PV generation is muted because sunlight is generally at lower strength as compared to summer hours where generation is more prominent to offset other demand modifiers adding load to the system.

Figure C-6: Total peak system day load and DER impacts (GW) by year, Scenario 2, Goal Aligned: 2025-2050 (Source: Kevala)



Scenario 2a introduces mitigation efforts through 50% managed charging of EVSE. The following charts show the system coincident peak days at the same scale for all years to show relative scale across the years. The dates for each year indicate the coincident system peak day. Compared to Scenario 2 (see Figure C-7), there is a pronounced reduction in the amount of EVSE charging in later years.

Figure C-7: Total peak system day load and DER impacts (GW) by year, Scenario 2a, Goal Aligned, Mitigation A (50%): 2025-2050 (Source: Kevala)



Scenario 2b increased managed charging to 100%. The following charts show system coincident peak days and the corresponding contribution to peak of all DERs throughout the peak day. Charts are all to the same scale to show relative growth and impact of DERs through the years.

As with the other scenarios, the coincident system net load peak shifts to winter by 2030. Additionally, the peak hour moved from evening hours to late morning. This shift is different from Scenarios 2 and 2a where the peak remained in the evening and into the later evening hours. With flattened EVSE charging curves, the peak hour is shifted to late morning before PV generation is increased to overcome the added contribution of HP HVAC.

Figure C-8: Total peak system day load and DER impacts (GW) by year, Scenario 2b, Goal Aligned, Mitigation B (100%): 2025-2050 (Source: Kevala)

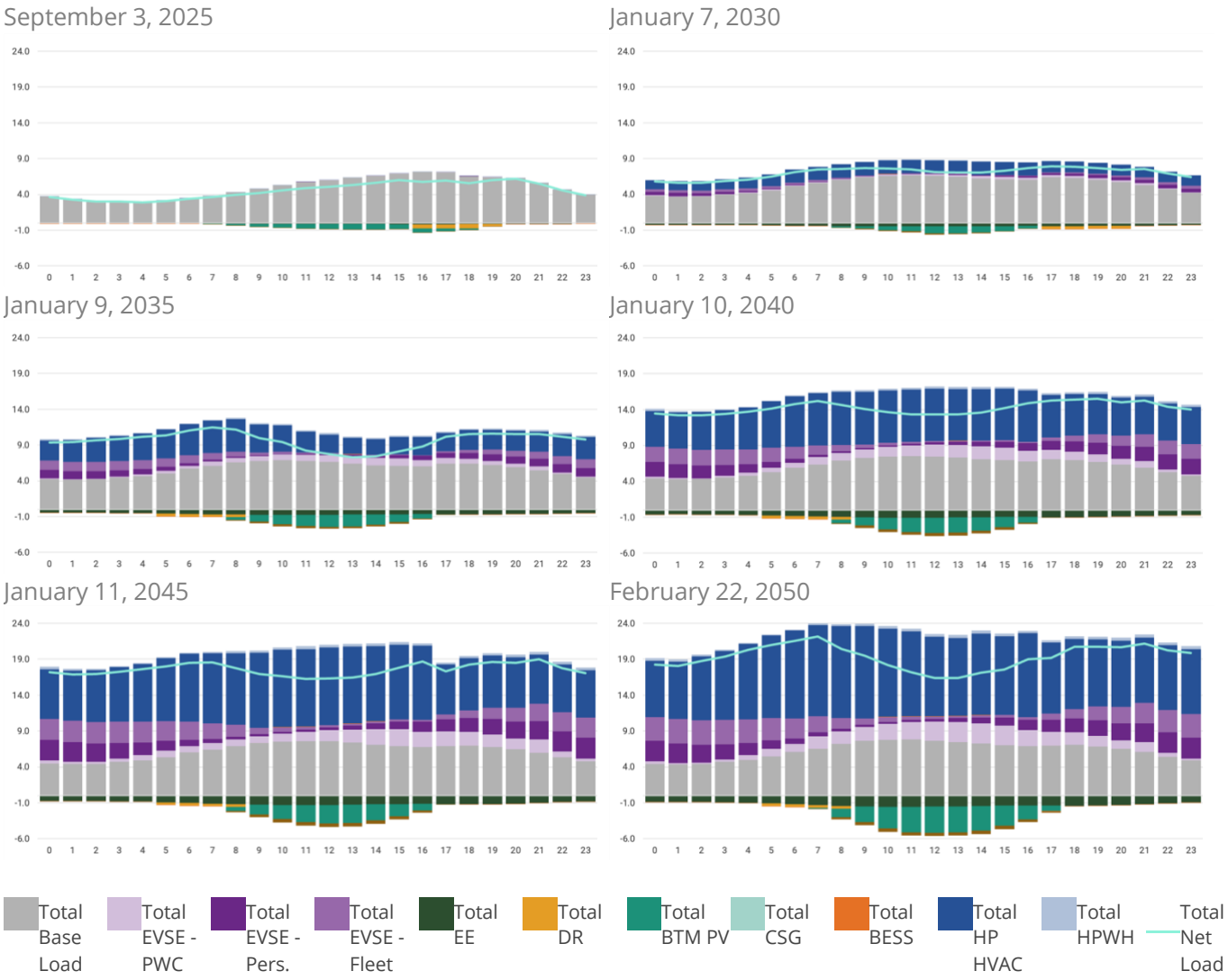
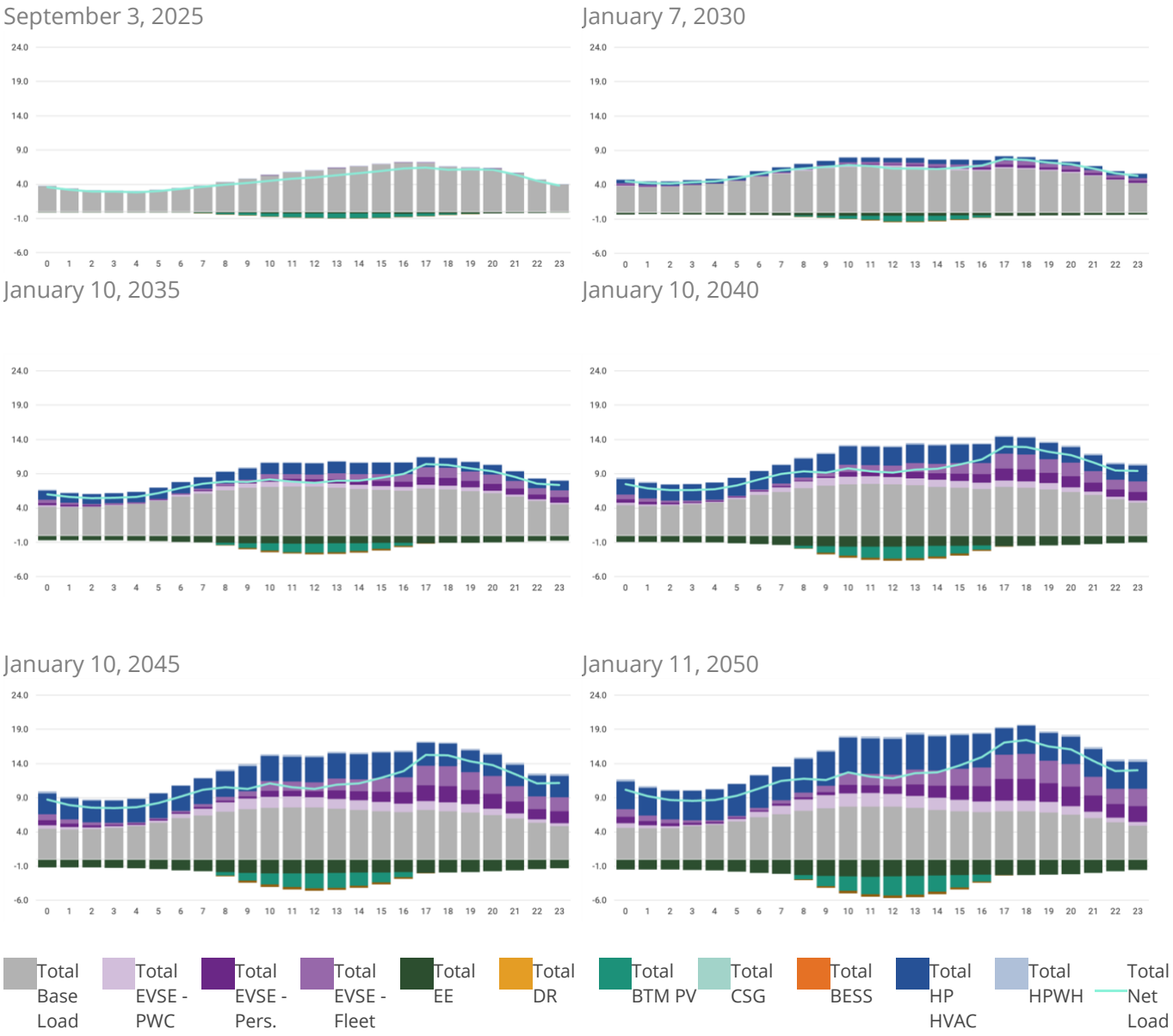


Figure C-9 shows Scenario 3 system coincident peak days. Each chart has the same y-axis scale to show the relative contribution to peak of a demand modifier.

By 2030, the system peak day shifts from late summer to January peak days. The peak hour remains in the evening, shifting to late evening in the later years. Peak hours shifting to later hours comes from the increased HP HVAC usage in winter evenings as well as charging of personal and fleet vehicles. PV generation impacted the system net load in later years, reflected as a dip of the net load curve in the middle of the day when sunlight is at its peak.

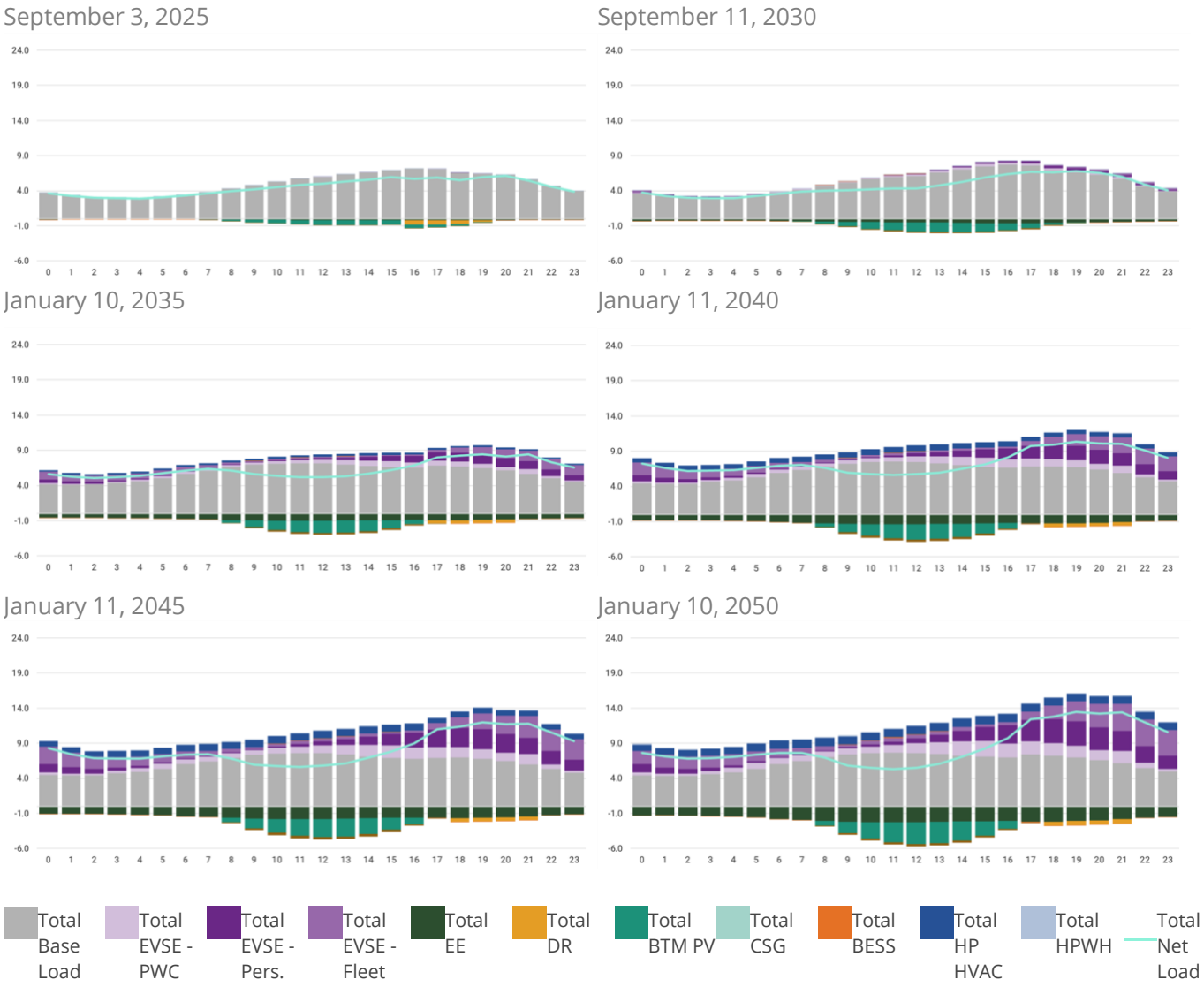
Figure C-9: Total peak system day load and DER impacts (GW) by year, Scenario 3, Calibration: 2025-2050 (Source: Kevala)



Scenario 4 system coincident peak days are shown below. The charts all have the same scale on the y-axis to show overall growth and demand modifier contribution to peak.

The BTM PV generation relative to DER adoption load impacts in Scenario 4 results in BTM PV still having a meaningful reduction in load during midday in 2050. The relative utility of BTM PV is showcased in this scenario because of the reduced target totals, which resulted in lower growth rates and showed a pronounced dip of net load in the midday of 2050 from the solar impact.

Figure C-10: Total peak system day load and DER impacts (GW) by year, Scenario 4, Adoption Trajectory: 2025-2050 (Source: Kevala)



The following are key findings from Kevala's analysis of the net load results:

- System coincident peak days shift to winter from late summer. The increased usage of HP HVAC units pushed the system peak day to winter and peak hour to later in the evening when there were increased adoptions.
- The two managed charging scenarios, Scenario 2a and 2b, flattened the EVSE charging curves as anticipated, resulting in more pronounced impacts from HPWH than other non-mitigated scenarios

Appendix D. Grid Capacity Needs Modeling Overview and Additional Results

D.1 Approach

Kevala compared forecasted net loads against distribution infrastructure ratings to determine if there were capacity violations (referred to as overloads) associated with normal or contingency capacity limits. Kevala assumed an overload when the forecasted load exceeded 75% of the feeder's capacity rating (feeders being the key driver for upstream new asset builds). This limit was provided by Public Service Company of Colorado (PSCo), representing a normal assumption on the grid and remained consistent throughout all scenarios and years.

For feeders, Kevala used the noncoincident peak hour of each month, differentiated between weekdays and non-weekdays, to determine an asset's peak load to calculate capacity overloads. If the resulting peak net load for a feeder exceeded 75% of the asset's capacity, an overload was recorded. This approach ensured that any load transferred between assets considered the peak hour of each individual asset to avoid an overload elsewhere on the grid as a result of the intended mitigation. For example, if two feeders had different noncoincident peak hours, load was not transferred from one feeder with an overload at one peak hour to another feeder with a different peak hour, leading to another overload.

Kevala used the peak load at different key infrastructure points of the grid (i.e., service transformers, feeders, substation transformer banks, and substations) to estimate if there was an overload:

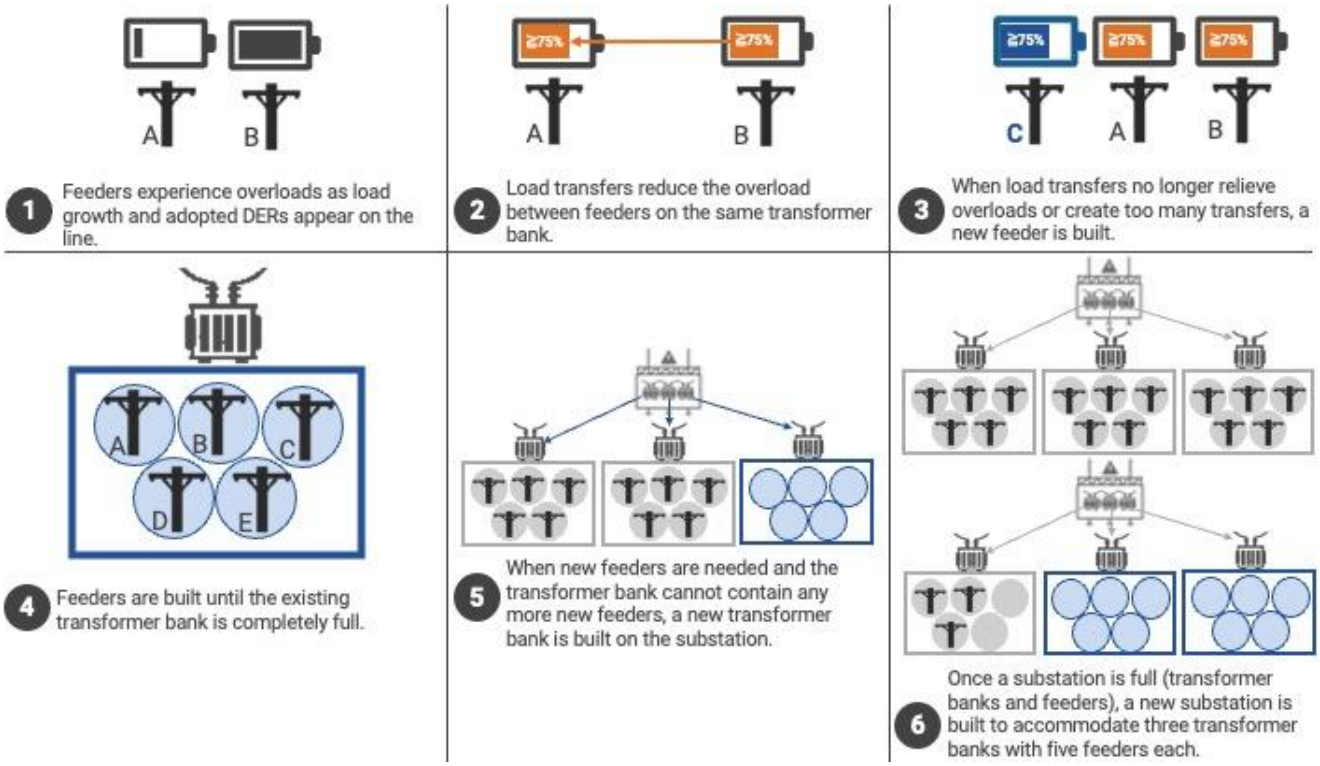
- If an overload was observed, the model first attempted to mitigate the overload through load transfers between feeders.
    - When load transfers occurred, additional analysis was conducted to assure any load transfers did not cause the need for another transfer on either impacted asset. Kevala assumed all load in excess of 75% capacity on a feeder was first transferred to a nearby feeder. The initial feeder (and any assets installed later) experiencing the overload was considered maxed out and did not take on any additional load above the 75% capacity.

- If load transfers were insufficient to solve the overload, new infrastructure assets of equal or increased size were added to address the overload. Feeders were added first until all feeder space on a transformer bank filled and then a transformer bank was added. New substations were constructed when all transformer bank space on existing substations were taken.

- The equipment upgrade hierarchy considered thermal capacity constraints and depended on typical rated capacities, substation configurations, and available space for new assets.
- New assets were chosen to match the limitations of the overloaded asset. Kevala added new service transformer capacity when constituent premises' aggregated demand rose above the asset's loading limit. New service transformer capacity was sized against a 5-year operational time horizon, and overloads were established at a 100% capacity loading limit. All new feeders were considered to be of an equal length, with percentages of their length modeled as overhead or underground, based on the overloaded asset.
- Anticipated future banks were provided by PSCo based on prior planning efforts. These constraints were on an individual substation basis and identified how many banks an existing substation would manage before a new substation would be needed. Future banks also identified how many feeders were allowed on the new banks.
- Once these future constraints were reached and the existing substation built to full bank capacity, any additional new substations were estimated to have room for three new banks with five feeders per bank.

Figure D-1 outlines this method.

Figure D-1: Capacity upgrade cost calculation method at different grid asset levels (Source: Kevala)

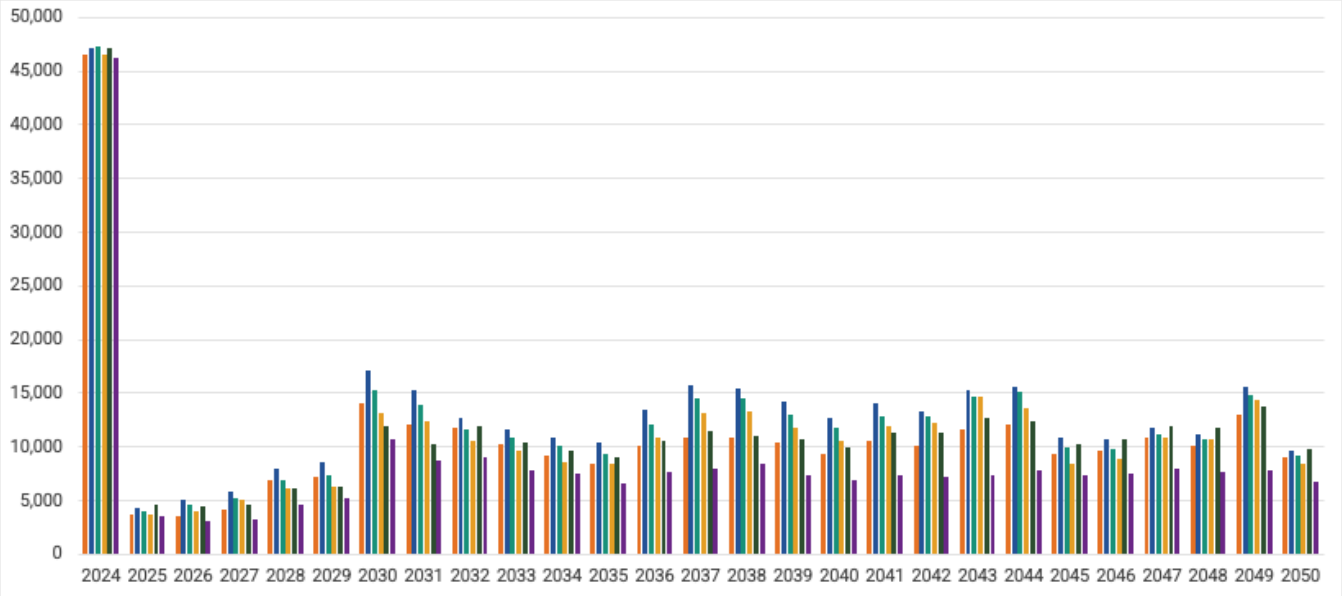


D.2 Analysis and Results

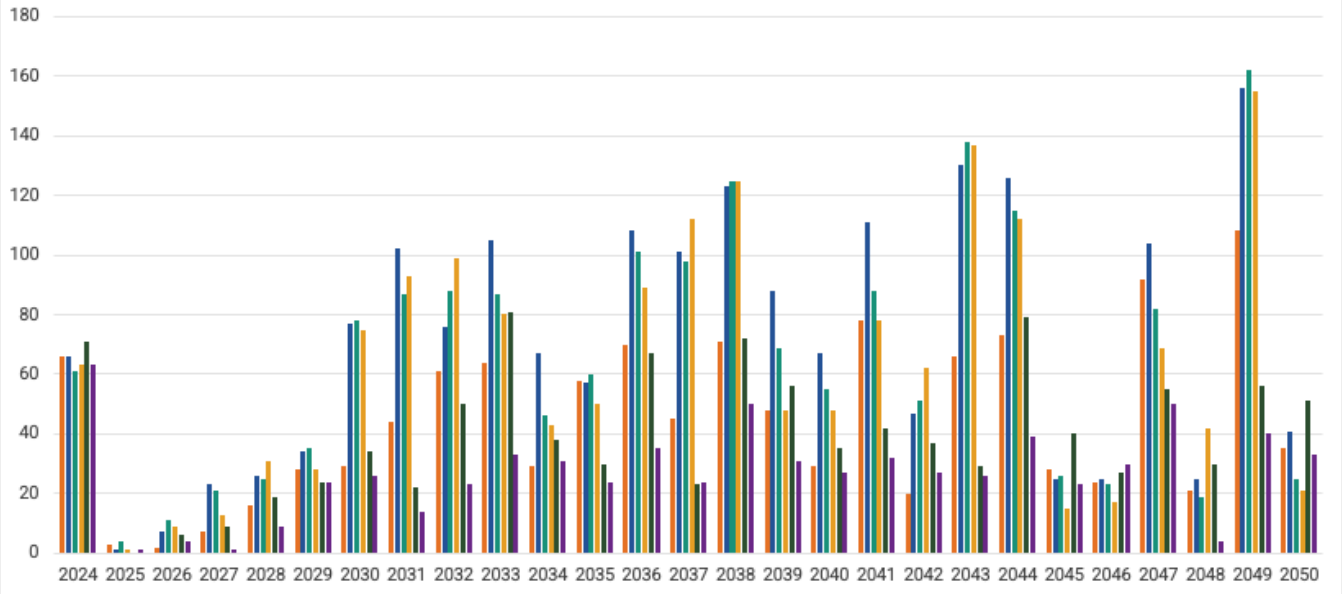
The difference in overloads among years and scenarios is due to increased DER adoptions. The most asset overloads are seen in Scenarios 2, 2a, and 2b where the DER adoption targets are greatest. Figure D-2 shows total counts of new assets by year and scenario. The modeling approach enforced a 75% utilization factor (in accordance with PSCo system design policies), triggering a new build based on existing assets that exceed this threshold. As discussed previously, this logic in the model triggered a large number of new assets in 2024.

Figure D-2: New assets by type, scenario, and year: 2024-2050 (Source: Kevala)

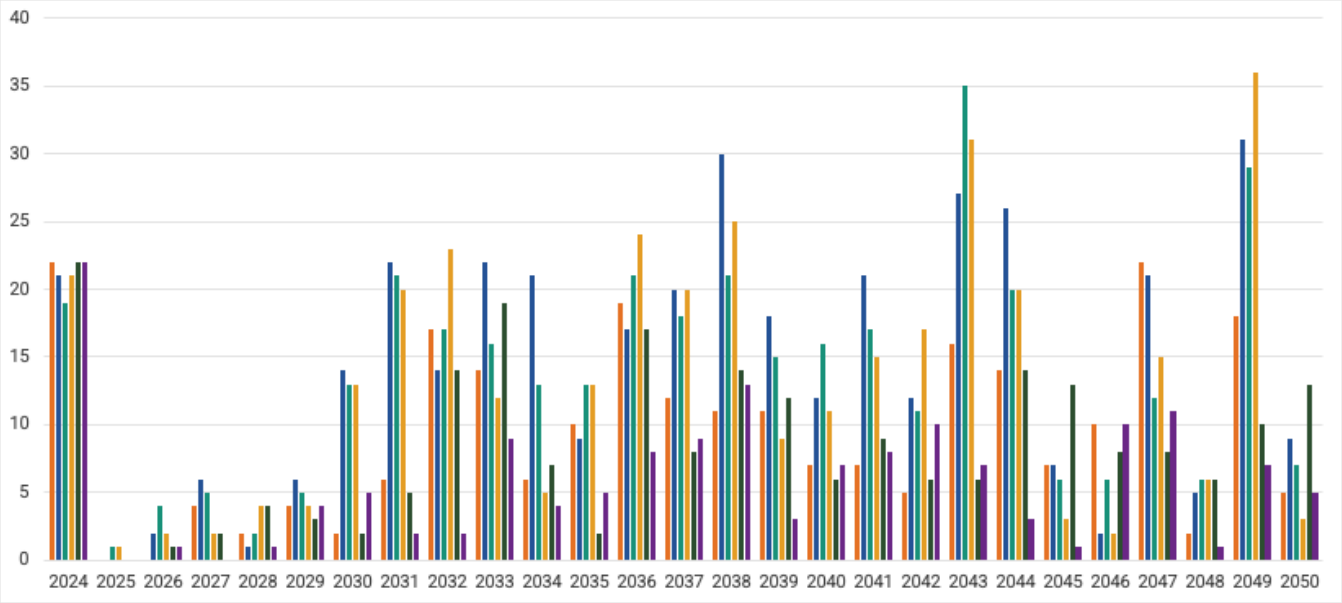
Service transformers



Feeders



Transformer banks



Substations

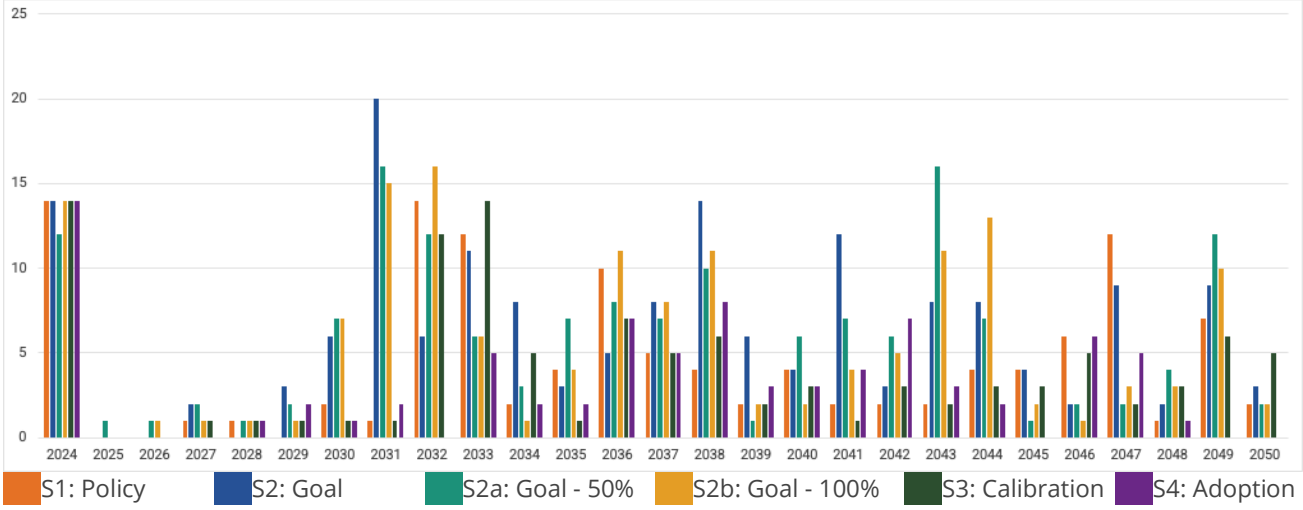
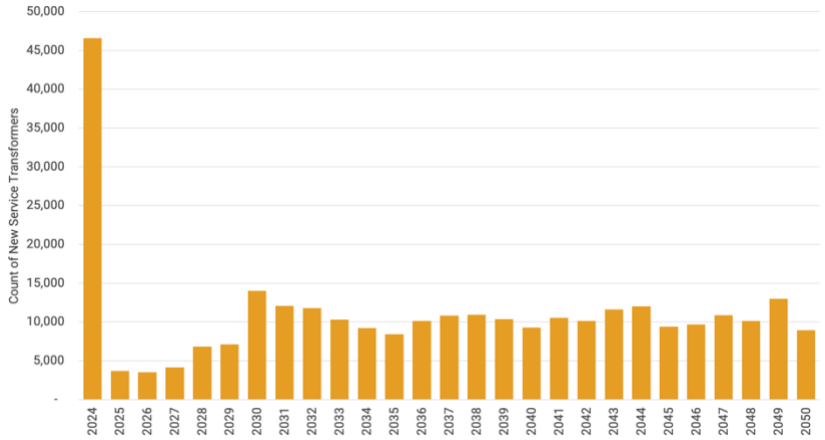


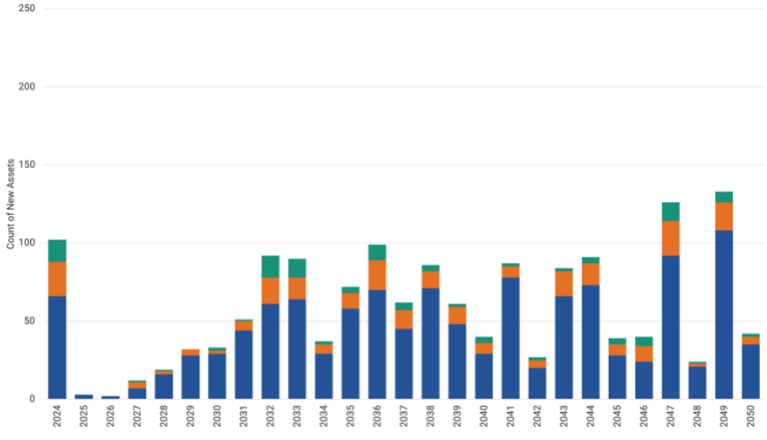
Figure D-3 shows total new service transformers (left chart) and total new feeders, banks, and substations added in each scenario in each year, 2024-2050. The charts are set to the same y-axis scaling for relative growth.

The charts indicated another wave of new builds around the year 2030 for all scenarios when the system coincident peak shifts to a winter peak from late summer. The increased heating in the winter created overloads for new assets on these system lines.

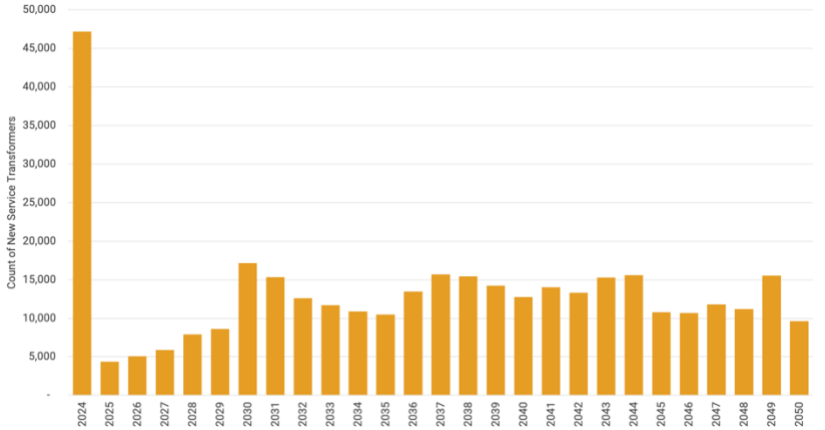
Figure D-3: Number of new assets by scenario, service transformers (left) and all other assets (right): 2024-2050 (Source: Kevala)

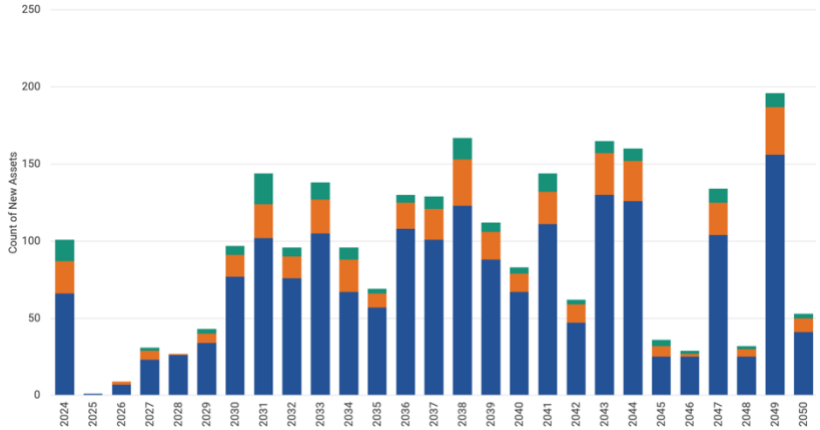
Scenario 1: Policy Aligned



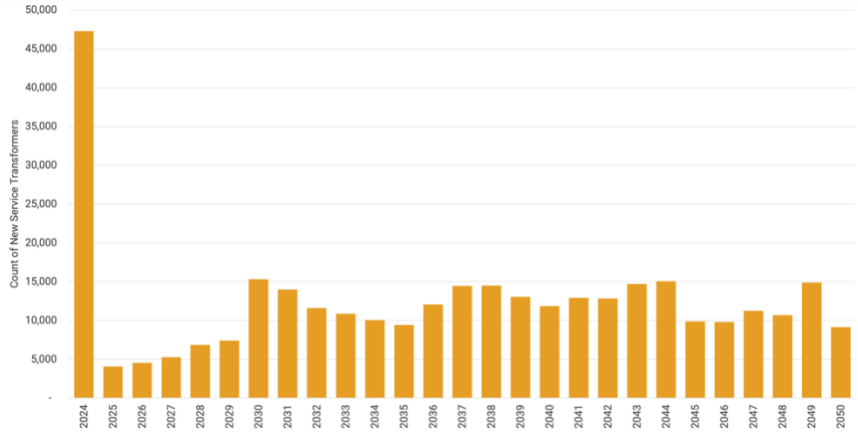


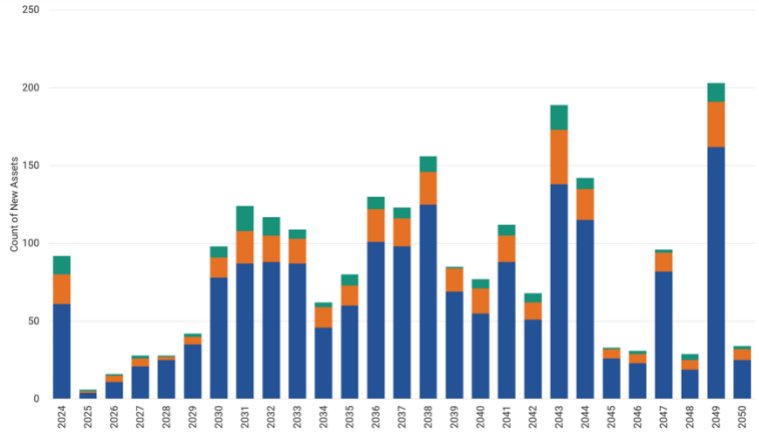
Scenario 2: Goal Aligned



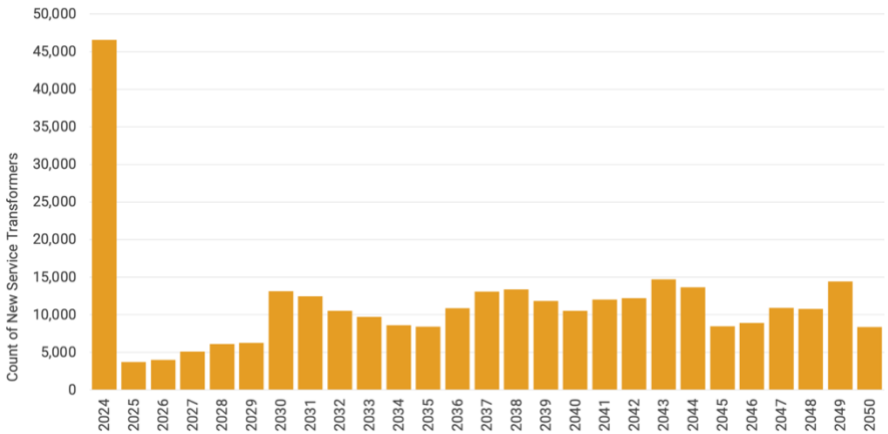


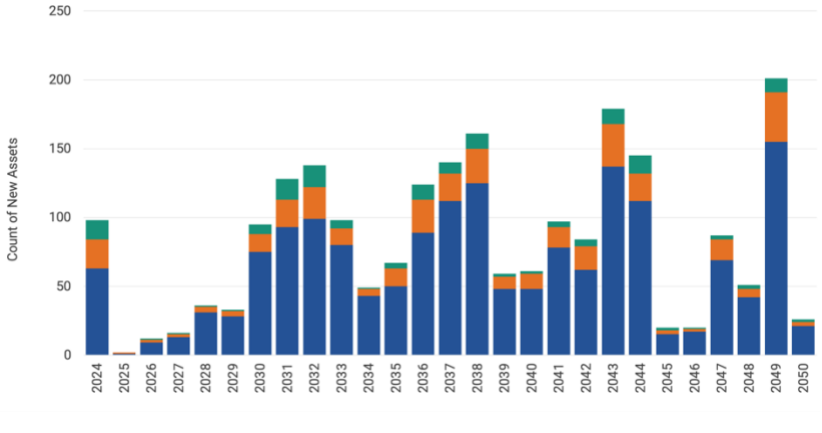
Scenario 2a: Goal Aligned, Mitigation A (50%)



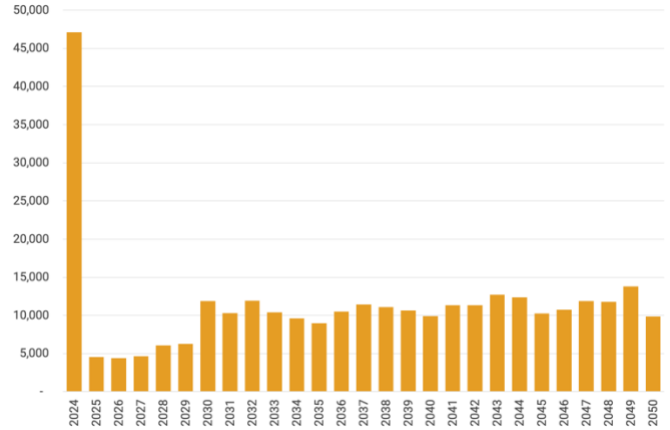


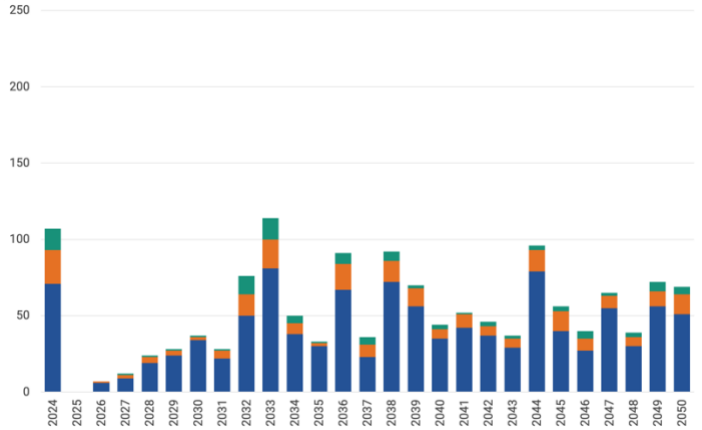
Scenario 2b: Goal Aligned, Mitigation B (100%)



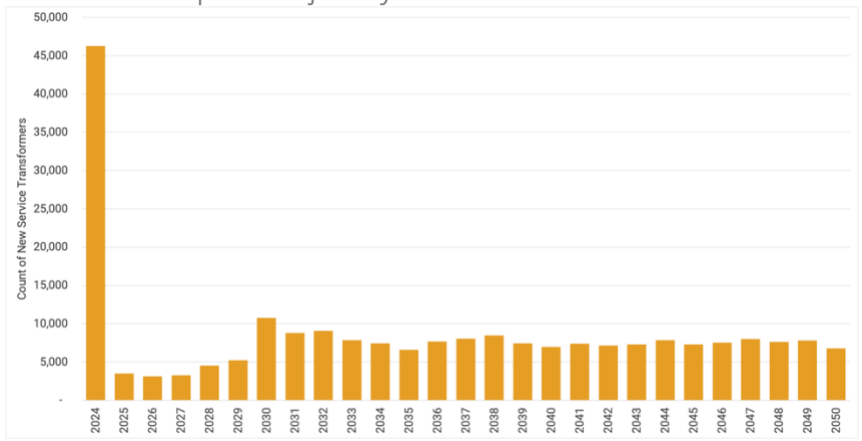


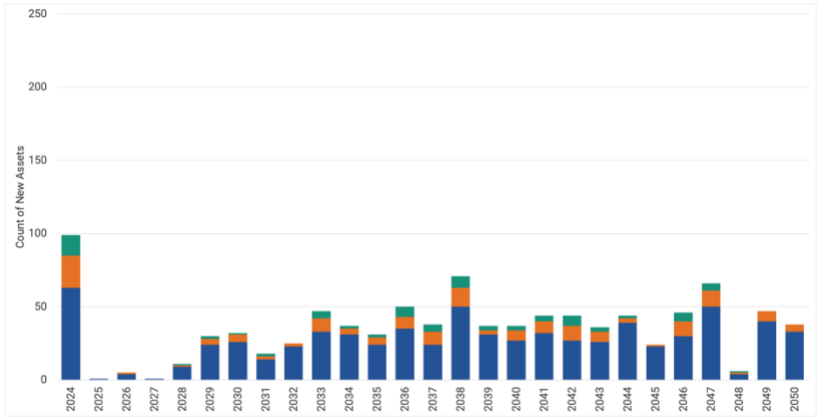
Scenario 3: Calibration





Scenario 4: Adoption Trajectory





Feeders Banks Substations Service Transformers

The following are key findings from Kevala's analysis of the grid capacity needs results:

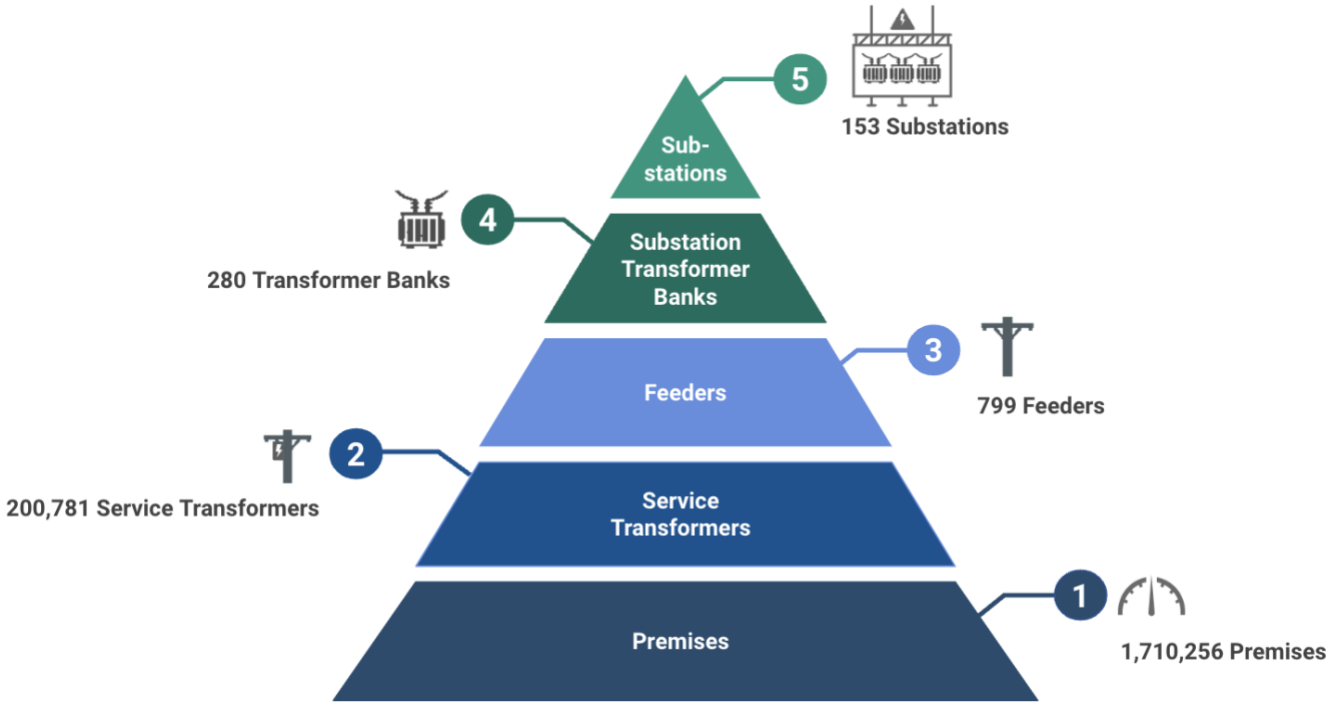
- 2024 has significantly more new asset builds compared to other years in all scenarios. This in part is the result of the 75% utilization factor triggering a new build. PSCo maintains several existing assets that do not adhere to this design specification.
- The need for service transformers tracks well with incremental DER adoptions that may be increasing loads and load growth.
- The need for feeder additions demonstrates variability in the level of available capacity. Because feeders are built when capacity exceeds 75% of load, feeders are starting at different utilization levels that then drive differences in the timing of feeder needs.
- Substation and substation transformer bank needs reflect a certain level of available capacity across PSCo's service territory that is saturated later in the study period as load growth and DER growth persists.

Appendix E. Upgrade Cost Estimates Modeling Methodology and Additional Results

E.1 Approach

Once new infrastructure assets required to mitigate overloads were identified (see Appendix D), Kevala used general unit costs (developed in collaboration with Public Service Company of Colorado, or PSCo) for these new assets to calculate upgrade cost estimates. Figure E-1 shows the relationship between the various grid assets that Kevala analyzed to determine capacity impacts.

Figure E-1: Pyramid showing the relationship between existing grid assets (Source: Kevala)



The unit cost of replacing each of the different assets increases from the bottom of the pyramid to the top—e.g., a new substation has higher unit costs while new service transformers have lower unit costs. Kevala provided costs to PSCo in 2024 equivalent dollars as well as nominal costs where an inflationary multiplier of 2.5% was added each year.

Kevala's method to calculate grid upgrade costs was based on the unit costs of grid assets and the overloads calculated in Appendix D. Substations were bucketed into three urbanization categorizations, acknowledging differences in construction and installation costs. For this study, an

asset was considered rural, urban, or dense urban.[43] Dense urban assets would be found in congested areas like Boulder or Denver. If a substation was considered rural, all the banks and feeders connected to it were also considered rural. Service transformers were assumed to have a single average cost-per-build.

E.1.1 Feeder Costs

Kevala considered both fixed and variable costs, including typical equipment and conductor costs, when calculating a feeder upgrade (see Table E-1). These costs included amounts for capacitor banks, reclosers, ducts, and other infrastructure. Kevala determined feeder length based on the average mainline length (~2.6 miles) of an PSCo-provided sample of feeders for each of the three urbanization categories (rural, urban, or dense urban).

Table E-1: Unit costs for feeders by line type and urbanization category (Sources: Kevala, PSCo)

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]

E.1.2 Substation, Substation Transformer Bank, and Service Transformer Costs

Kevala maintained the same three urbanization categories when determining substation and substation transformer bank costs (see Table E-2). These amounts are independent of additional feeders needed to build out a new substation transformer bank or the substation transformer banks needed to build out a new substation. Kevala used a common average cost value, provided by PSCo, for service transformers.

Table E-2: Unit costs for substations and substation transformer banks by urbanization category (Sources: Kevala, PSCo)

[redacted]	[redacted]		
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[43] Kevala determined an asset's urbanization category using data from PSCo or, if not available, publicly available data by census tract from the U.S. Department of Transportation, Bureau of Transportation Statistics, "Local Area Transportation Characteristics for Households (LATCH Survey)," February 2021, https://www.bts.gov/latch

Asset Type	Cost ($/unit)		
	Rural	Urban	Dense Urban
Service Transformer	$12,000	$12,000	$12,000

This approach is based on the following assumptions:

- Kevala's approach does not include PSCo's in progress or planned future projects. If a new transformer bank was planned to be included on an existing substation and had different build constraints from the assumed five feeders per bank, a new bank with the smaller constraints would be used. However, Kevala did not plan for these new assets to be online at the same time PSCo planned and instead brought them online when overloaded feeders were determined.
- Costs are shown in the year of the overload. No costs were "brought forward," meaning the full cost of the asset is seen in the year of the overload was triggered.
- The method does not include land constraints for substations or constructability costs. Kevala assumed the buildouts of new substations and banks would be feasible in the same location.

E.2 Analysis and Results

Table E-3 shows the grand total upgrade costs by year for all assets. This total is for all service transformers, feeders, banks, and substations across all years. Scenarios 2, 2a, and 2b with the highest targets required the most new assets and therefore incurred the highest upgrade costs.

Table E-3: Grand total (in nominal dollars) of all assets across all years by scenario: 2024-2050 (Source: Kevala)

Scenario	Total Asset Upgrade Costs
Scenario 1: Policy Aligned	$34,011,246,640
Scenario 2: Goal Aligned	$51,236,362,903
Scenario 2a: Goal Aligned, Mitigation A (50%)	$47,571,515,283
Scenario 2b: Goal Aligned, Mitigation B (100%)	$45,701,790,788
Scenario 3: Calibration	$31,057,169,222
Scenario 4: Adoption Trajectory	$20,982,153,002

Figure E-2 graphically depicts the totals in Table E-3. The cumulative costs for all assets increase reasonably similarly until around 2030. From that year onward, the cost and growth of Scenario 2, 2a, and 2b is significantly higher than the other scenarios. The curves of those higher growth,

higher cost scenarios reflected each other with the reductions in costs being directly related to the impacts of managed charging on infrastructure needs.

Figure E-2: Cumulative nominal costs (using 2.5% inflationary factor) by year by scenario for all asset types, 2024-2050 (Source: Kevala)

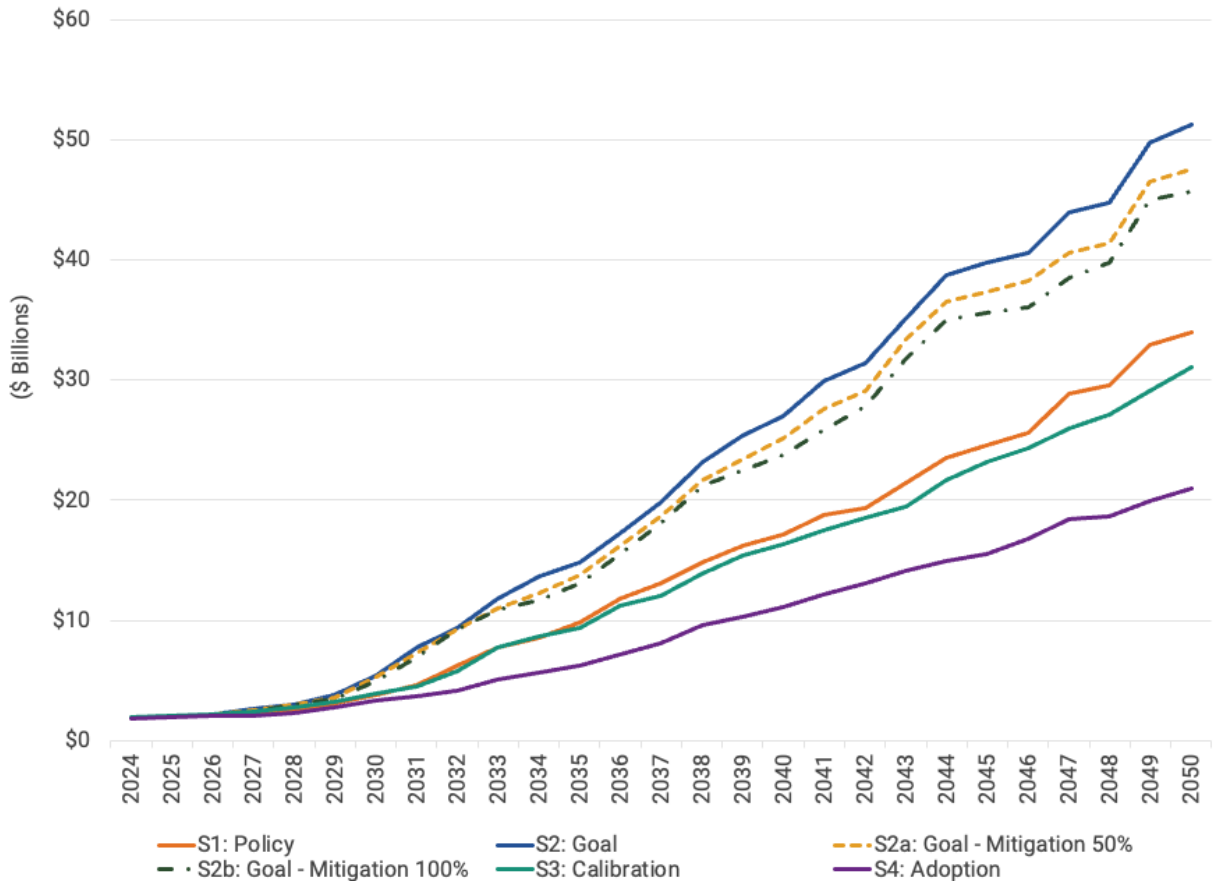
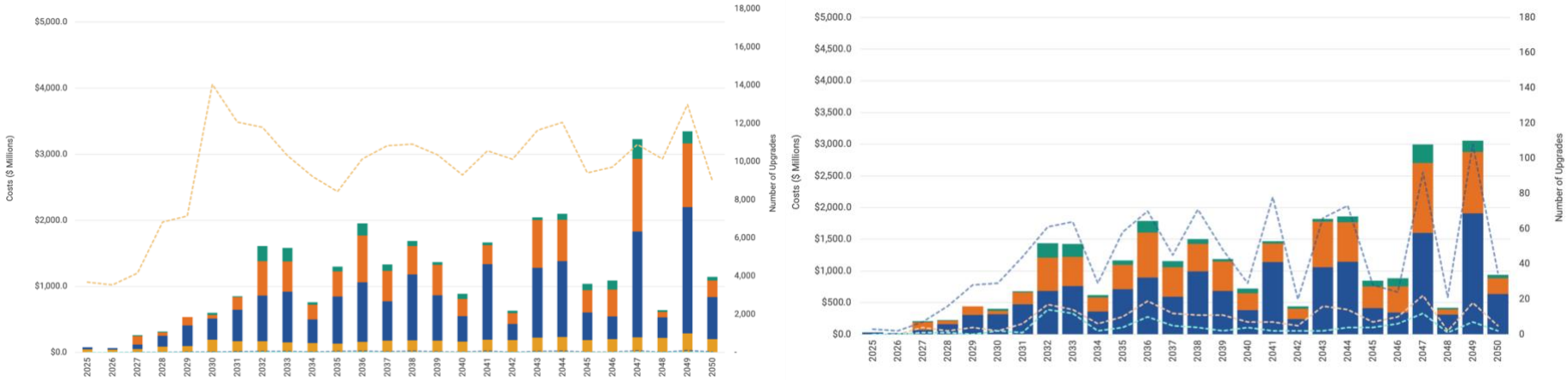


Figure E-3: Upgrades counts and costs (2.5% per year inflation) with (left) and without (right) service transformers by scenario and asset type: 2024-2050 (Source: Kevala)

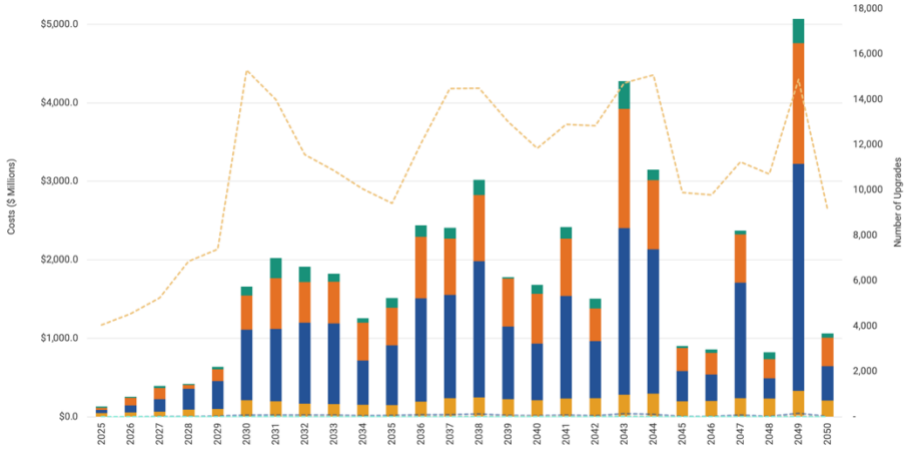
Scenario 1: Policy Aligned

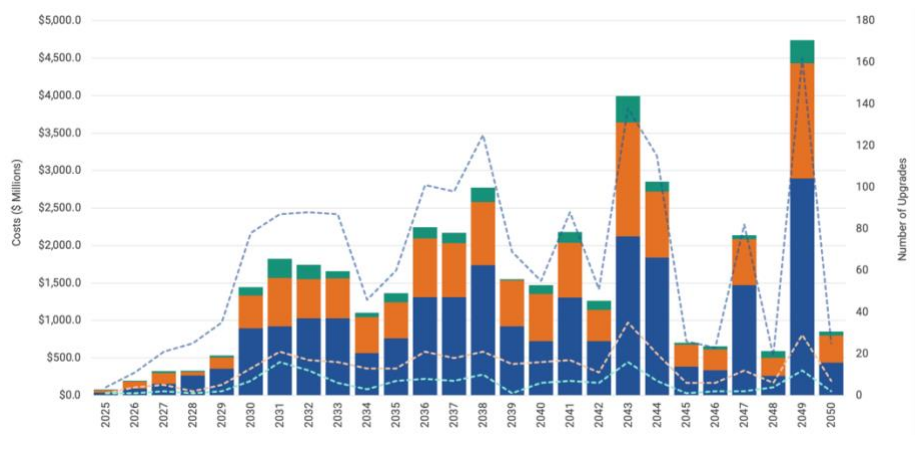


Scenario 2: Goal Aligned

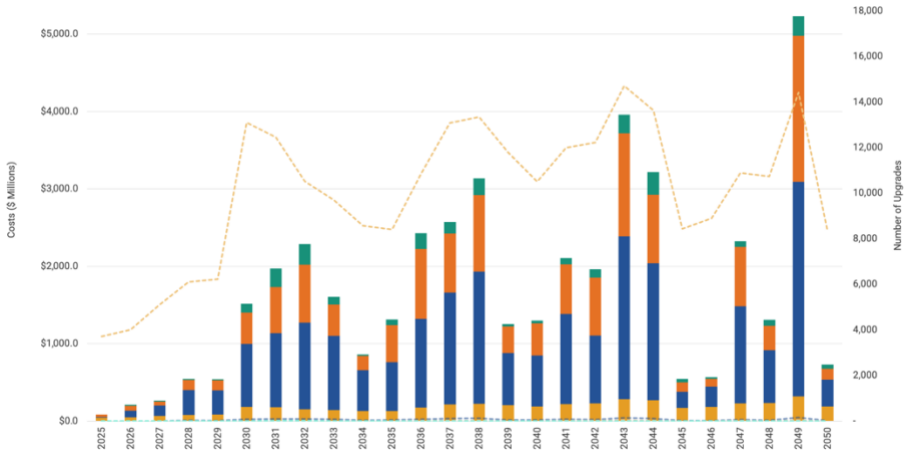


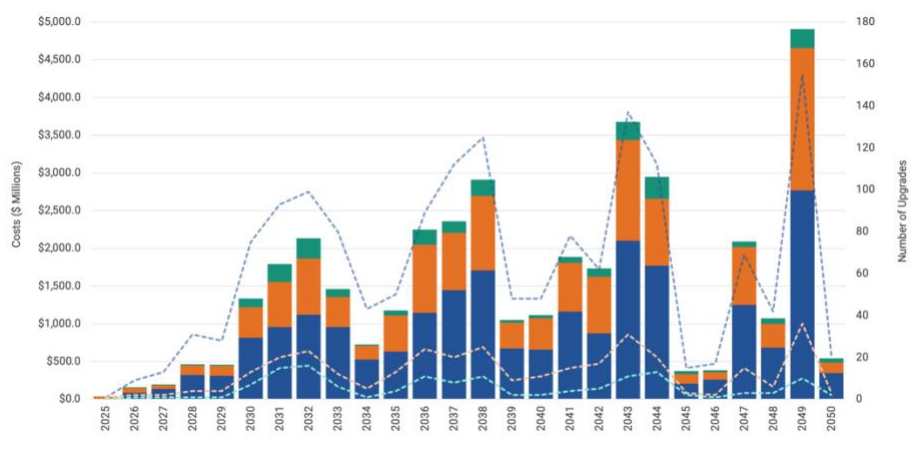
Scenario 2a: Goal Aligned, Mitigation A (50%)





Scenario 2b: Goal Aligned, Mitigation B (100%)





Scenario 3: Calibration



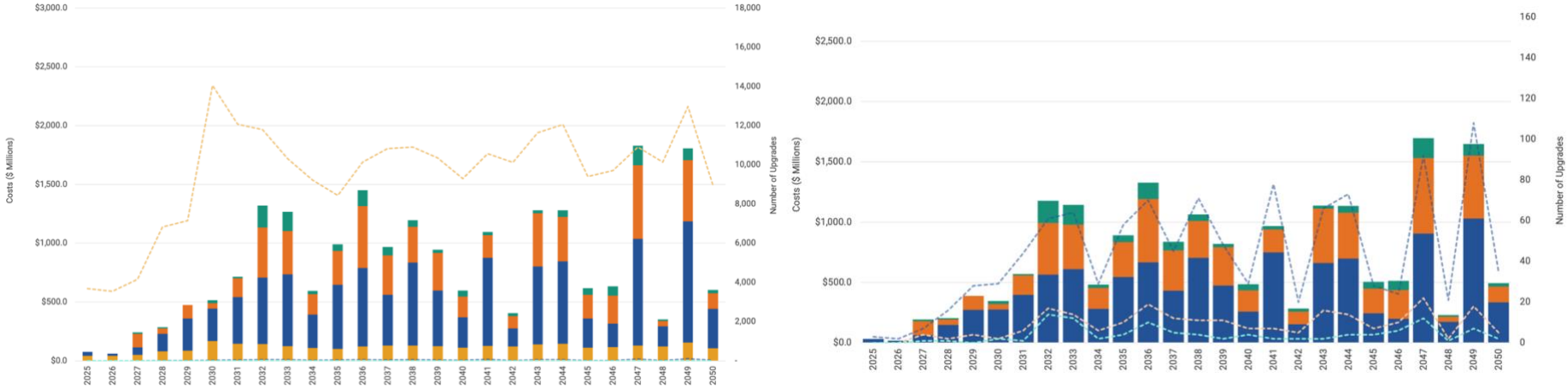
Scenario 4: Adoption Trajectory



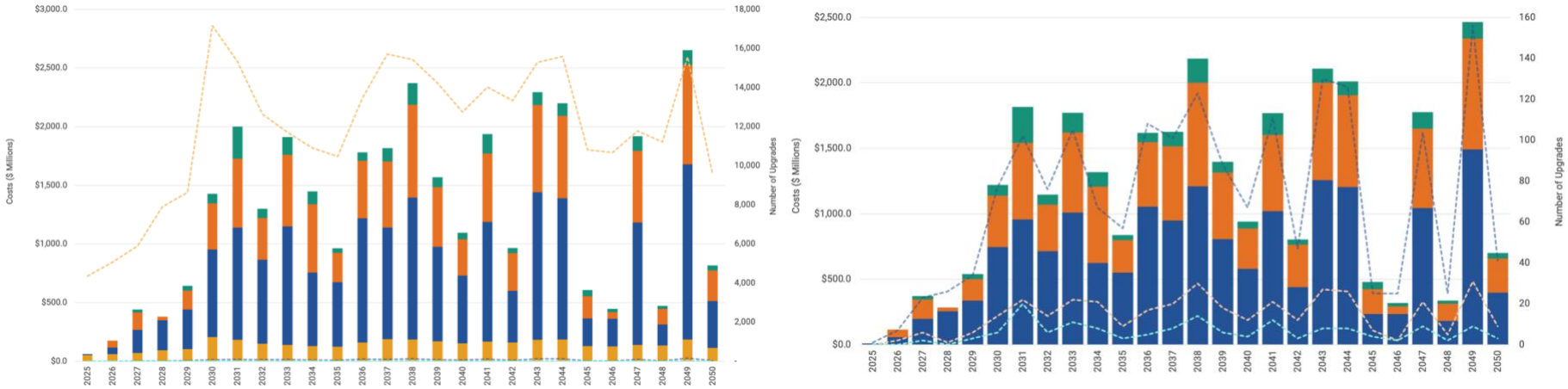
Feeder Cost
Bank Cost
Substation Cost
Service Transformer Cost
Number of Feeders
Number of Banks
Number of Substations
Number of Service Transformers

Figure E-4: Upgrades counts and costs ($2024) with (left) and without (right) service transformers by scenario and asset type: 2024-2050 (Source: Kevala)

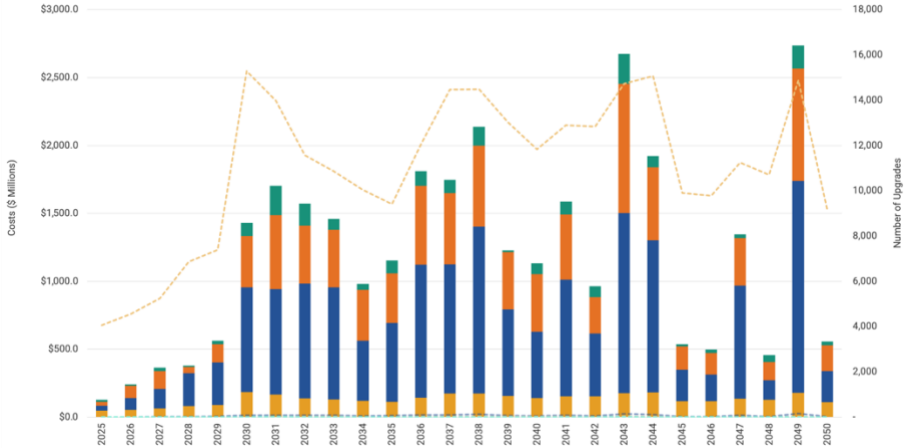
Scenario 1: Policy Aligned

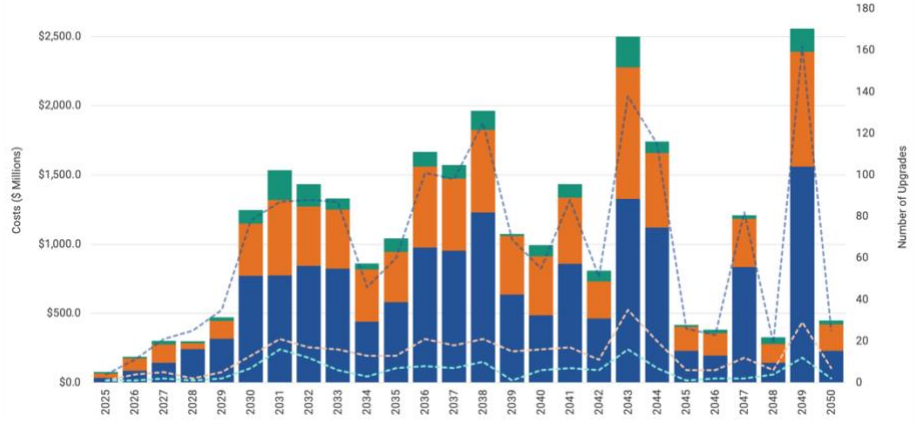


Scenario 2: Goal Aligned

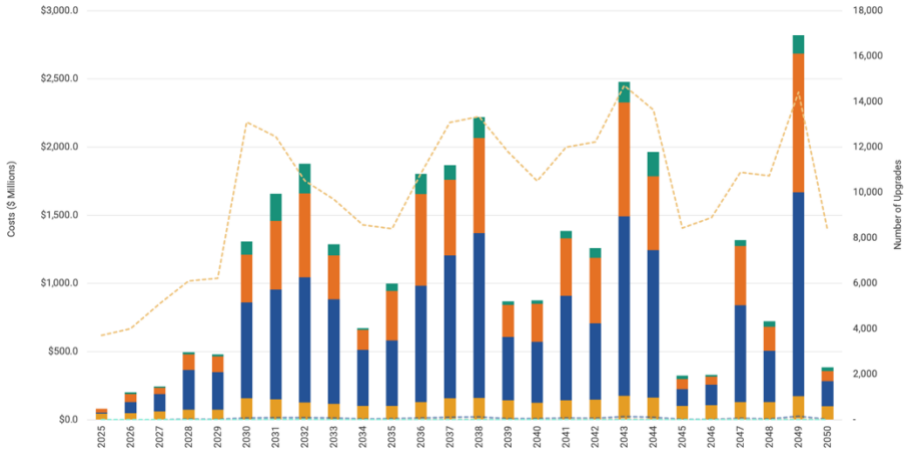


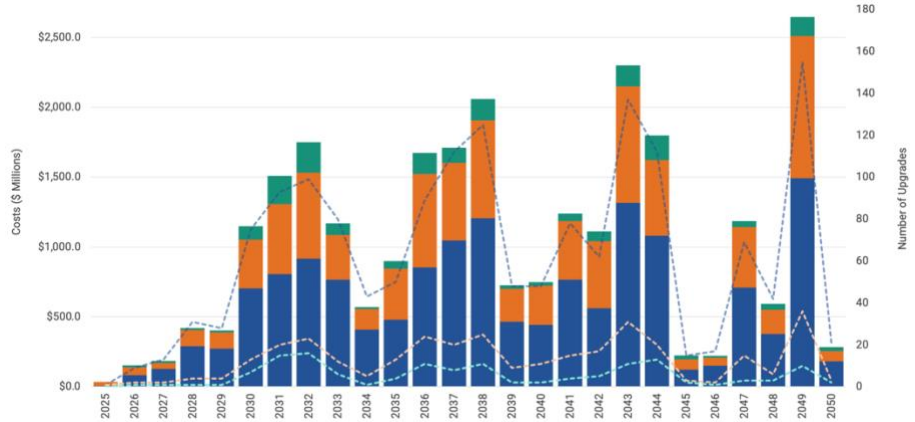
Scenario 2a: Goal Aligned, Mitigation A (50%)





Scenario 2b: Goal Aligned, Mitigation B (100%)

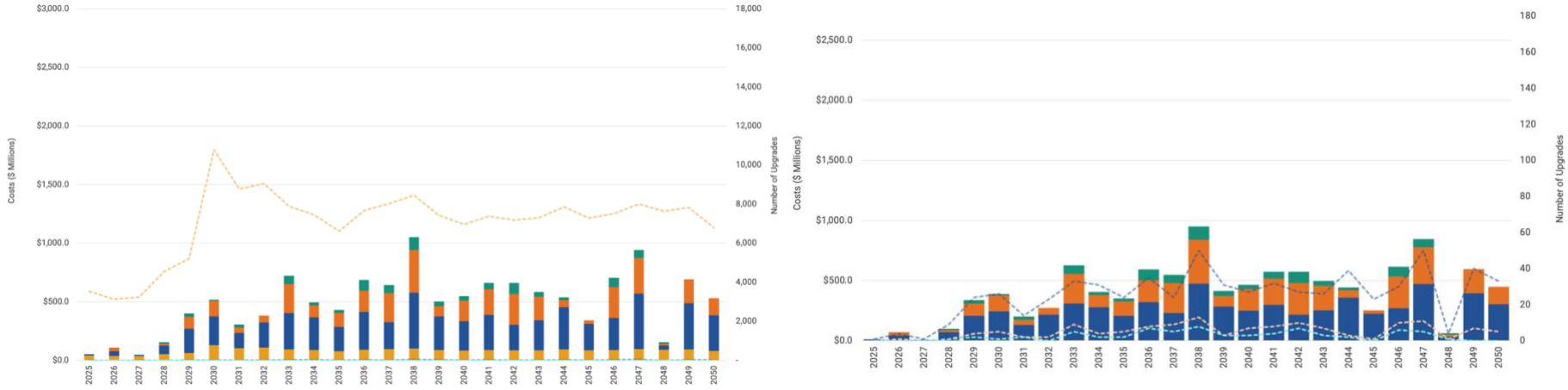




Scenario 3: Calibration



Scenario 4: Adoption Trajectory



Feeder Cost
Bank Cost
Substation Cost
Service Transformer Cost
Number of Feeders
Number of Banks
Number of Substations
Number of Service Transformers

The following are key findings from Kevala's analysis of the upgrade cost estimates:

- Cost estimates reflect the grid needs and the unit costs for each grid addition.
- These costs are irregular over time, particularly because when substation capacity is needed, transformer banks are also built, creating significant capacity but low utilization. This result is consistent with PSCo's current practices, though the real-world impacts are more pronounced.

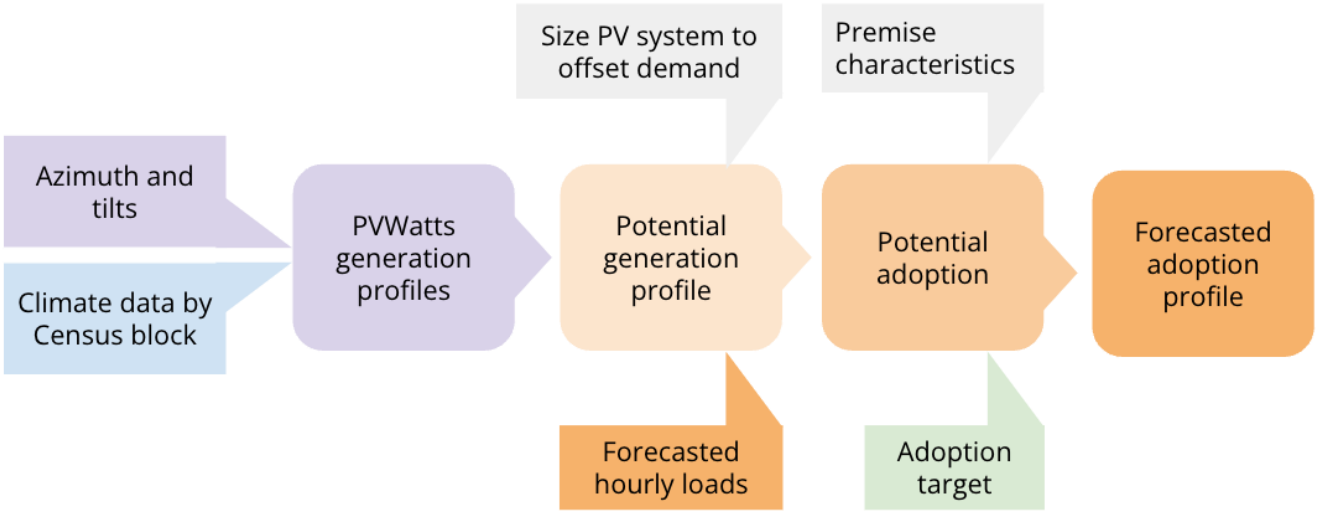
Appendix F. Solar PV Modeling Methodology and Additional Results

F.1 Approach

Kevala's approach to solar photovoltaic (PV) modeling required estimating the behavior, size (i.e., PV system rating), and adoption for behind-the-meter (BTM) and community solar garden (CSG) PV systems. BTM included residential and commercial and industrial (C&I) systems.

Figure F-1 shows Kevala's modeling approach to determine premise-level PV demand modifier estimates. This approach used client-provided data (e.g., location and system ratings of known PV systems) and Kevala's geospatial platform datasets, which derive from public and proprietary sources (e.g., typical system characteristics, weather data). Given a service territory-level PV adoption forecast provided by PSCo, the model predicted the most likely year-by-year adoption dates, locations, characteristics of adopted systems, and resulting 8,760 (yearly hourly) generation time series curves.

Figure F-1: Flow diagram of solar PV modeling (Source: Kevala)



F.1.1 Behavior

To model the hourly behavior of BTM PV, Kevala created 1 kW DC system representative PV behavior simulations (1 kW DC PV standard profiles) for a set of geographical areas and assigned them to individual premises using customer revenue classifications provided by PSCo. For CSG, Kevala directly simulated the generation of each individual adoption based on predicted installed capacity and corresponding block group-level weather data.

Kevala used NREL's PVWatts tool[44] to generate behavior profiles for BTM and CSG. The key inputs for PVWatts were:

- Weather time series with a block group-level spatial resolution[45]
    - Direct and diffuse irradiance
    - Temperature
    - Wind speed
- PV system parameters
    - Panel tilt, in degrees (i.e., up or down)
    - Azimuth, in degrees (compass direction)
    - DC/AC ratio[46]
    - DC capacity
- Location information
    - Latitude
    - Longitude
    - Time zone
    - Elevation

LBNL's Tracking the Sun dataset[47] was used to account for realistic tilt and azimuth inputs:

- Tilt: The methodology differed for BTM PV and CSG.
    - For BTM PV, one tilt value was defined per customer revenue class per census tract. Tilt values were calculated using typical data from PV systems that were close to the latitude of the census tract of interest (based on zip code information).
    - For CSG, the tilt angle was set equal to the system's latitude.
- Azimuth: The methodology inferred common configurations from national data of system designs. An east-, west-, or south-facing system was allocated to each potential adopter based on their customer revenue class and statistically representative orientations.

Weather time series inputs for PVWatts included the characteristics of the weather forecast Kevala considered across all of PSCo's scenarios. To model degradation of PV panels, Kevala reduced the efficiency of all PV systems by 0.5% per year. To model retirement for CSG systems, the generation was set to 0 after 20 years.

[44] NREL's PVWatts Calculator, https://pvwatts.nrel.gov/
[45] NREL, "Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC)," accessed through the Open Energy Data Initiative (OEDI), dataset last updated September 22, 2023, https://dx.doi.org/10.25984/1970814
[46] PSCo provided a DC/AC ratio of 1.25.
[47] Lawrence Berkeley National Laboratory, Tracking the Sun, 2023 edition, https://emp.lbl.gov/tracking-the-sun

F.1.2 Sizing

The first step of sizing was to determine whether the premise or parcel was eligible for a PV system. Kevala developed distinct eligibility criteria for BTM and CSG systems:

For BTM PV, premises were eligible to adopt PV if:

- The customer revenue class of the premise was known.
- No other premises at the parcel had existing PV.
- One of the following was true about the premise's parcel:
    - There was only one premise at the parcel.
    - All premises at the parcel were non-residential, in which case only the premise with the highest annual demand was eligible.
    - Either two or three multifamily residential premises were at the parcel, in which case only the premise with the highest annual demand was eligible.

For CSG, parcels were eligible to adopt PV if they:

- Met specific land area requirements typically associated with CSG development (e.g., parcel area, distance to closest distribution feeder).
- Did not have a building footprint.

Once a parcel was determined to be eligible for CSG adoption, a potential system of 0.5 MW up to 5 MW capacity was assigned considering parcel size and a panel's ground coverage ratio. For BTM PV-eligible premises, Kevala established the potential size of the system by linearly scaling the corresponding customer sector's 1 kW DC standard BTM system to meet a defined percentage of the premise's annual demand (before PV adoption). Kevala sized systems to meet a fixed percentage of annual demand, limited by rooftop area. For residential premises, the percentage was 100%, while for C&I, it was based on empirical PV-to-annual energy usage ratios.

F.1.3 Adoption

To predict which premises were most likely to adopt PV, the model assigned each premise an adoption propensity score between 0 and 1. For BTM systems, the adoption score equals the weighted average of a density score and a financial score.

- The density score was calculated as a normalized ratio between the number of premises with adopted PV in any given census tract and the number of PV-eligible premises in that tract.
- The financial score, which reflects whether it makes financial sense for a particular premise to adopt PV, was calculated as the annual creditable generation divided by the system cost, where annual creditable generation is the smaller of annual demand and annual PV generation. For system costs, nationwide summary data from LBNL's Tracking the Sun

dataset was used to create a function that calculated the installed price per kW of a PV system based on its size.

For CSG systems, the adoption score equals the weighted average of an irradiance score and a size score.

- The irradiance score was calculated as the normalized total annual global horizontal irradiance.
- The size score was calculated as the similarity to typical CSG system size, chosen to be 2 MW based on Kevala subject matter expertise.

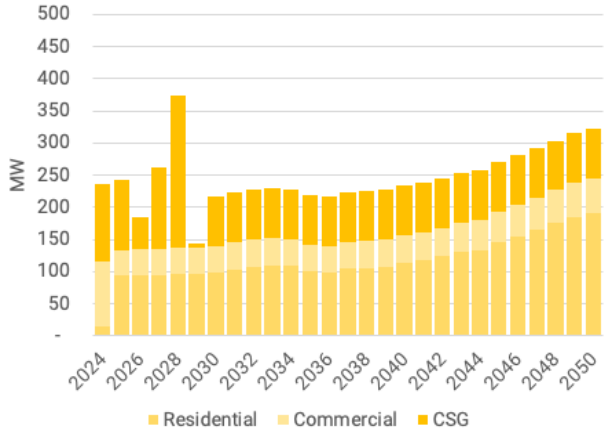
A higher adoption propensity score indicates that a premise is more likely, relative to others within the same customer sector, to adopt PV. Because conditions at a premise can change over time, Kevala calculated adoption scores yearly. Each year, adopting premises were selected one at a time from all eligible premises that had not already adopted PV until the service territory's top-down yearly target capacity was reached.

Figure F-2 shows the PV targets used for this study by scenario. PSCo provided targets for BTM systems— broken out between the residential and C&I customer classes—and for CSG. Figure F-3 shows these same targets compared by sector (residential, C&I, and CSG). Finally, Figure F-4 shows the cumulative targets by scenario. As these charts show, Scenario 3 (Calibration scenario) has lower PV adoptions in all years, driven by lower residential BTM. In the other five scenarios,[48] CSG is slower to develop, and BTM residential is much higher in the front end and then declines after 2034.

[48] Scenario 2a: Goal Aligned - 50% Mitigation and Scenario 2b: Goal Aligned - 100% Mitigation have the same adoption targets as Scenario 2: Goal Aligned. When Scenario 2 is listed, it may be assumed to show the targets for Scenarios 2a and 2b.

Figure F-2: PV target adoptions (MW) by class, scenario, and year: 2024-2050 (Sources: PSCo, Kevala)

Scenario 3: Calibration



Scenario 1: Policy Aligned, Scenario 2: Goal Aligned, and Scenario 4: Adoption Trajectory

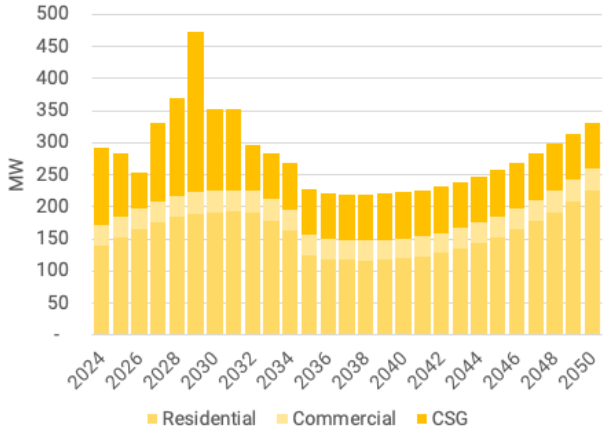
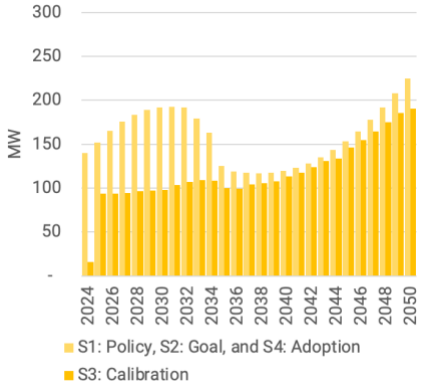
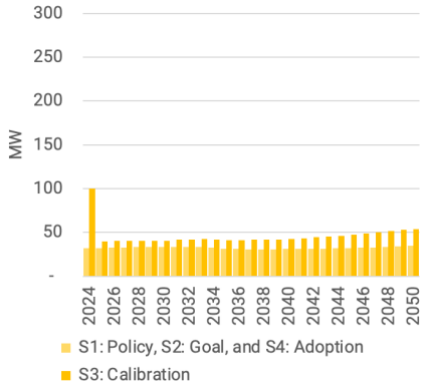


Figure F-3: Comparison of PV target adoptions (MW) by class, scenario, and year: 2024-2050 (Sources: PSCo, Kevala)

Residential



Commercial



CSG

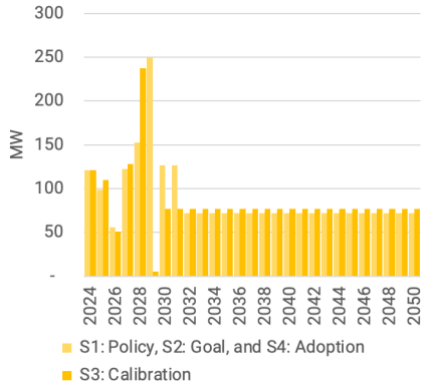
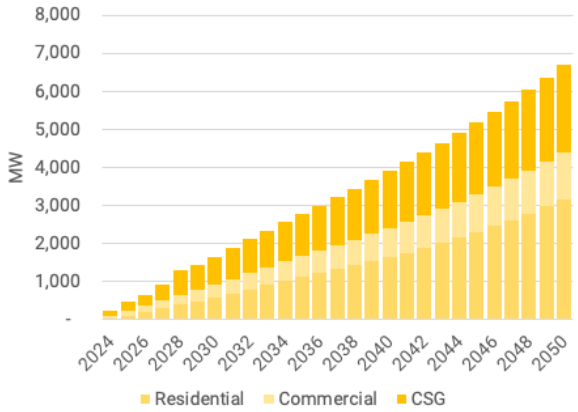
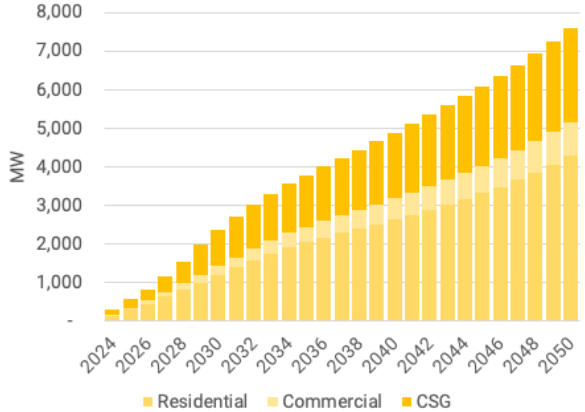


Figure F-4: Cumulative PV target adoptions (MW) by class, scenario, and year: 2024-2050 (Sources: PSCo, Kevala)

Scenario 3: Calibration



Scenario 1: Policy Aligned, Scenario 2: Goal Aligned, and Scenario 4: Adoption Trajectory



The following are the key assumptions associated with PV modeling:

- Kevala used common industry default specifications, except where noted. These default specifications included PVWatts' default assumptions about soiling, shading, and wiring losses (applied equally at every hour in the year), inverter efficiency, and module type (standard crystalline silicon).
- Premises known to already have installed PV systems were not eligible for adoption.
- Due to the eligibility criteria for CSG sizing used in this study (see Appendix F.1.2), a high proportion of adoptions resulted in systems being clustered on a small number of feeders. This clustering led to large negative loads at the substation level when the CSG generation loads were aggregated up from feeders to substations. In those instances, Kevala curtailed hourly excess CSG generation to bring the feeder-level net load as close to zero as possible.[49] This approach does not take into consideration new feeders built in areas that would be eligible for CSG adoption in later forecast years.
- The Policy Aligned, Goal Aligned, and Adoption Trajectory scenarios started with the same targets but different seed values. This allows for variability in the premises adopting DERs among scenarios even when the targets are the same and allows for identification of adoption volatility on certain feeders. This further enhances the benefits of the EIM bottom-up approach by adding insights into which feeders may have significant variability in DER adoption over time.

F.2 Analysis and Results

As discussed previously, the Policy Aligned, Goal Aligned, and Adoption Trajectory scenarios had considered the same total PV adoption by year (see Figure F-2), while the Calibration scenario had different PV adoption targets. PV results for all of these scenarios are discussed in more detail below.

F.2.1 BTM PV

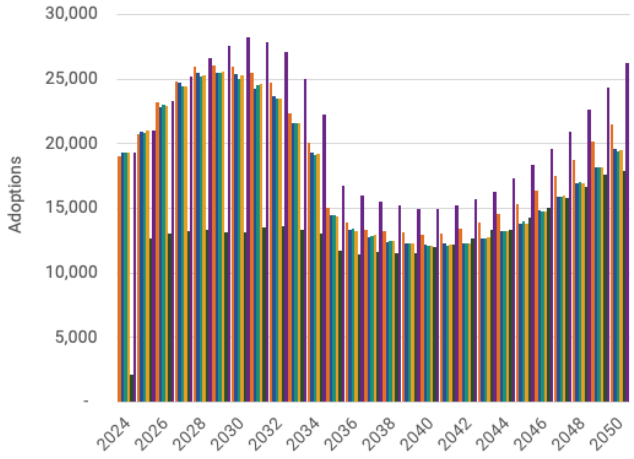
The following figures show the results of the BTM PV adoptions by scenario, year, and class. Figure F-5 shows incremental (i.e., the number each year) and cumulative BTM PV adoptions by scenario and year. These adoptions track with the targets shown in Figure F-2.

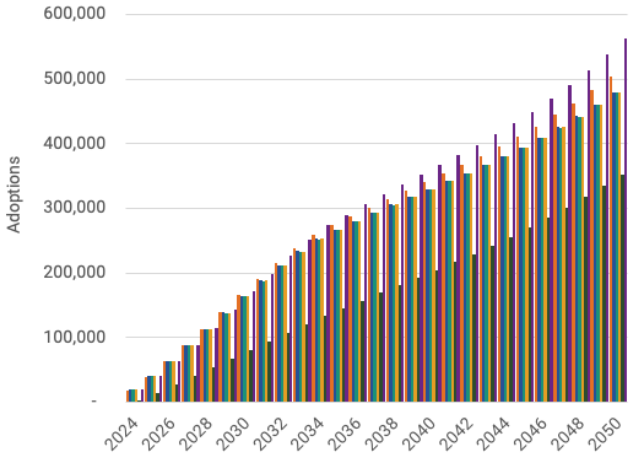
Figure F-5: Incremental and cumulative BTM PV adoptions by class, scenario, and year: 2024-2050 (Source: Kevala)

Residential - Incremental

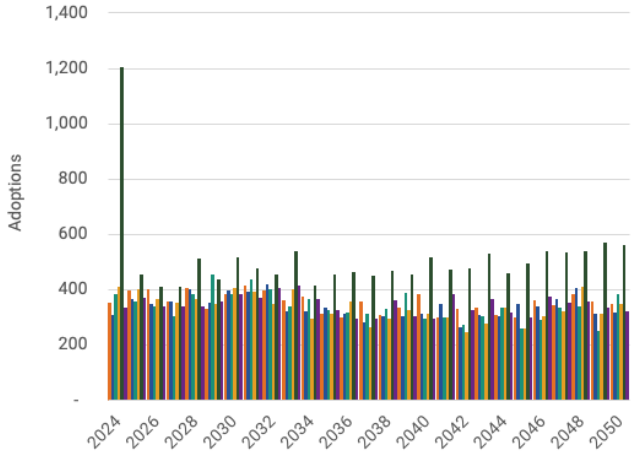
Residential - Cumulative

[49] In some cases, midday BESS and BTM PV activity still resulted in backflow on some feeders.

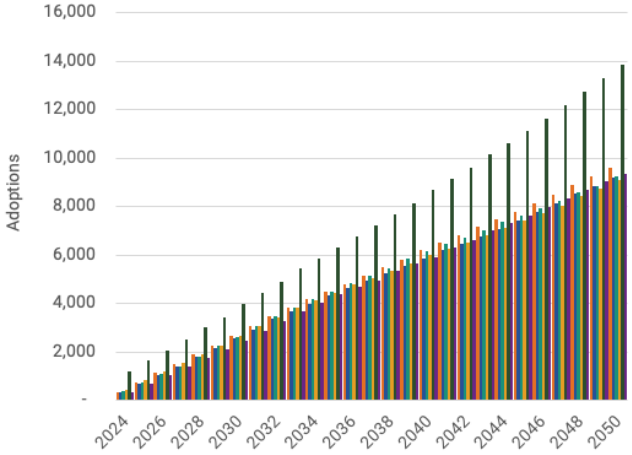




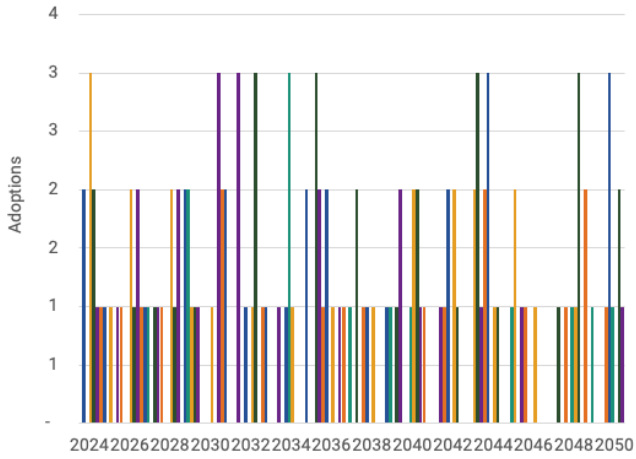
Commercial - Incremental



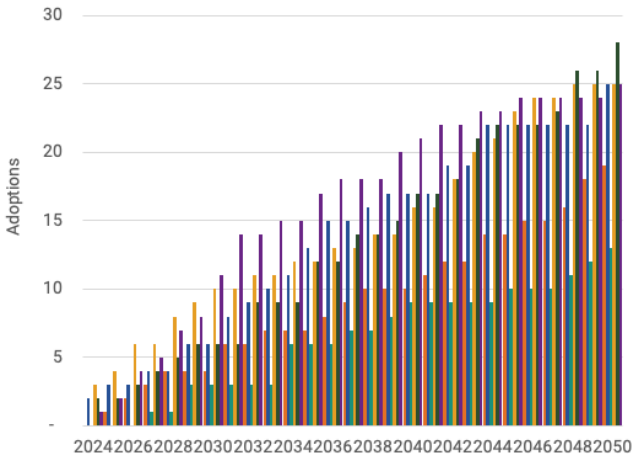
Commercial - Cumulative



Industrial - Incremental

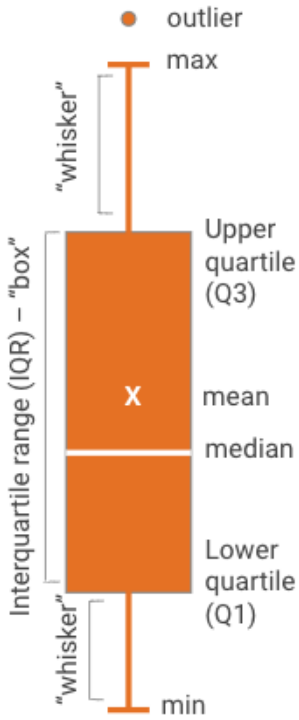


Industrial - Cumulative



S1: Policy S2: Goal S2a: Goal - 50% S2b: Goal - 100% S3: Calibration S4: Adoption

Figure F-6: Box and whisker plot overview (Source: Kevala)

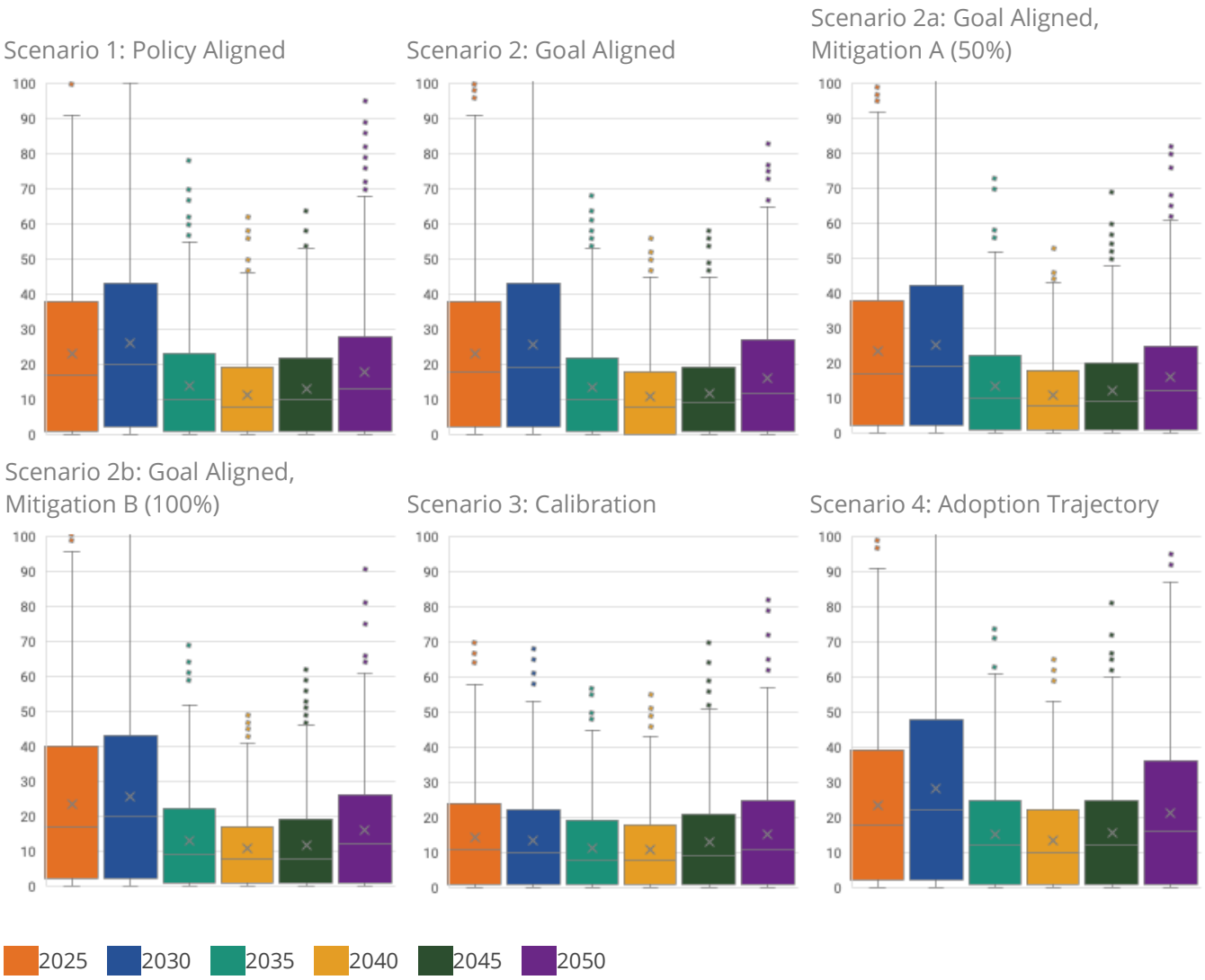


Throughout this report, Kevala uses box and whisker plots to illustrate results. Figure F-6 to the left explains the box whiskers. A box and whisker chart shows the distribution of data into quartiles, highlighting the mean and outliers. The box may have lines extending vertically called whiskers. The box represents the range of values between the upper (Q3) and lower (Q1) quartiles, and is often referred to as the interquartile range (IQR), which is calculated as Q3 minus Q1. The IQR illustrates the range of the middle 50% of the data. The whiskers show the additional range of value, with the caps being the minimum and maximum value excluding outliers. The dots represent outliers, defined as values greater or less than 1.5 times the IQR.[50] The line in each block denotes the median, the "x" is the mean, and the box designates the range of the lower and upper quartiles. Box and whisker plots provide a quick visual summary of a distribution of values, key statistics, and outliers, making it easy to compare the feeder-level results and identify trends like skewness or extreme values.

Figure F-7 shows the distribution of residential BTM PV adoption per feeder for each scenario for 2025, 2030, 2035, 2040, 2045, and 2050. The x-axis shows the study year while the y-axis shows the range of the number of residential BTM PV adoptions. The values for 2025 demonstrate that the distribution of PV adoptions for each scenario declines after 2030 and then starts to increase again in 2040, consistent with the targets provided by PSCo and shown in Figure F-2 through Figure F-4.

[50] The outliers to the top are values 1.5*IQR + Q3 while the dots below are Q1-1.5*IQR.

Figure F-7: Distribution of residential BTM PV adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)



While the targets remained constant from a gigawatt direct current (GW DC) capacity perspective for Scenarios 1, 2, and 4, the adoptions varied. This is because the simulation started with different seed values.[51] Kevala used different seed values to identify any biases in adoption propensity. That is, if the difference in the number of adoptions did not change significantly, the size of systems also did not change significantly among the scenarios. This is further substantiated by Figure F-8, which shows cumulative capacity of PV adoptions (GW DC) by class.

[51] Seed value is the initial value in a stochastic process. Using the same seed value will always result in the same outcome, while a different seed value will result in a different outcome.

Figure F-8: Cumulative BTM PV capacity (GW DC) by class, scenario, and year: 2024-2050 (Source: Kevala)

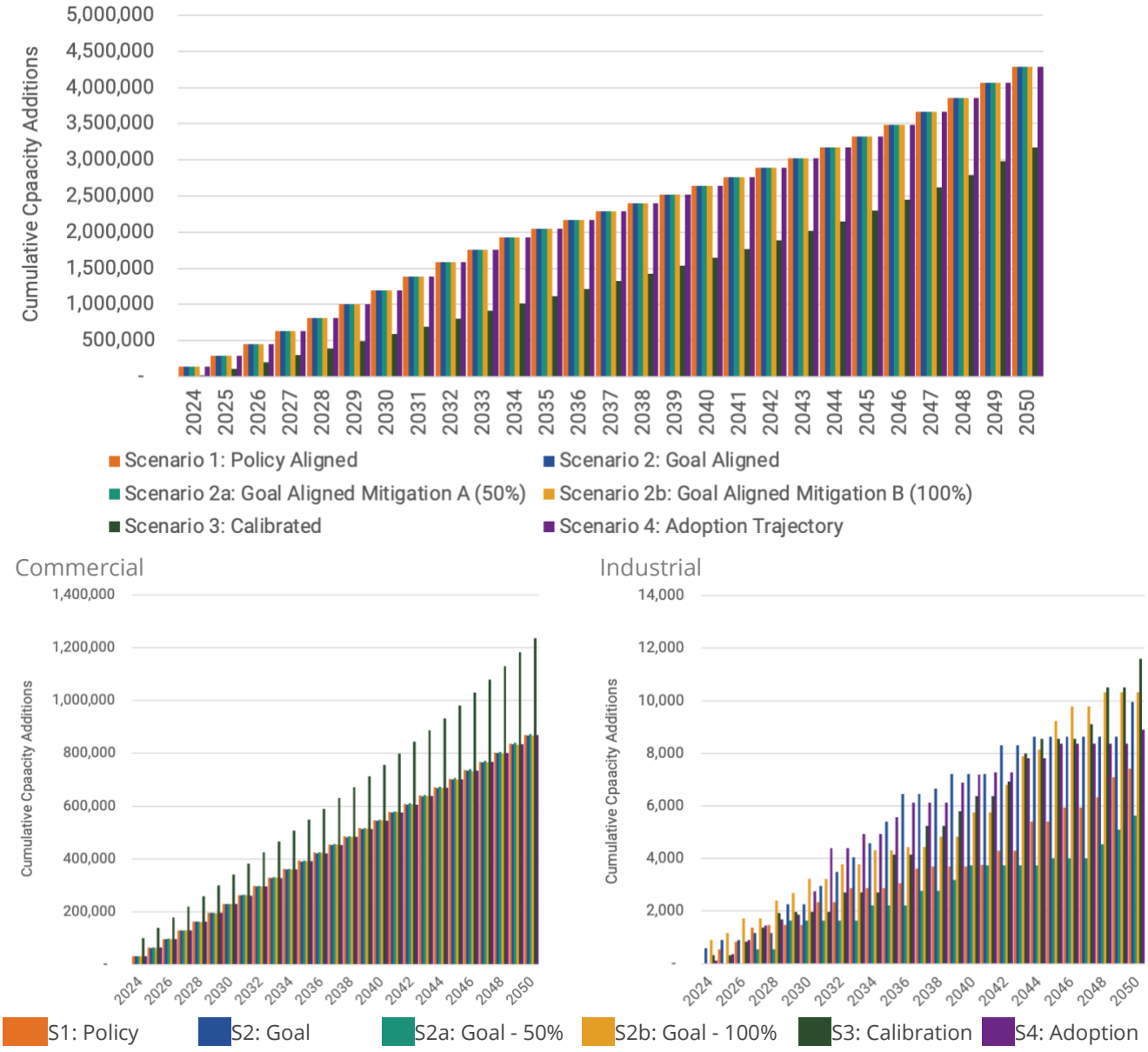
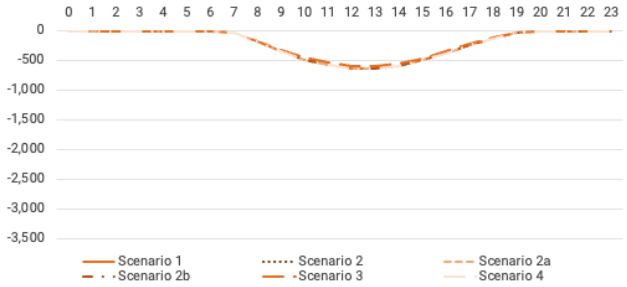


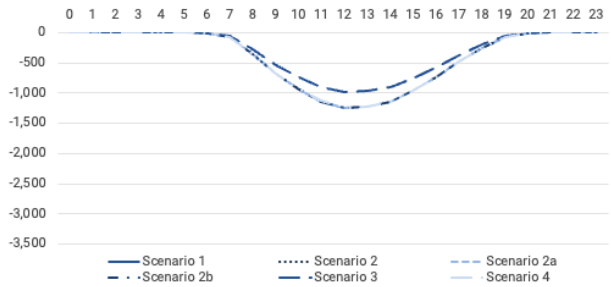
Figure F-9 shows the average BTM PV load shapes for each scenario and certain years. These charts show the expected average generation behavior from BTM PV systems, and the slight differences among the scenarios over the years. Note these charts are showing average BTM PV generation at the premise and do not include losses. All y-axis scales are equal to show differences in the average load shape across the scenarios.

Figure F-9: BTM PV average load shape (kWh) by scenario and year: 2025-2050 (Source: Kevala)

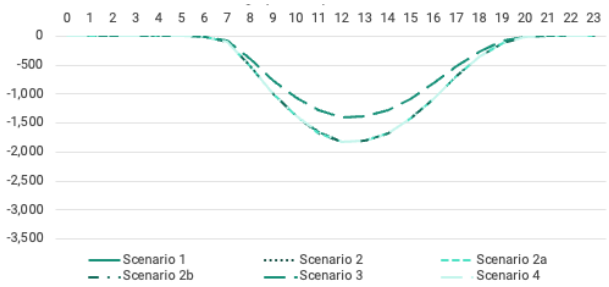
2025



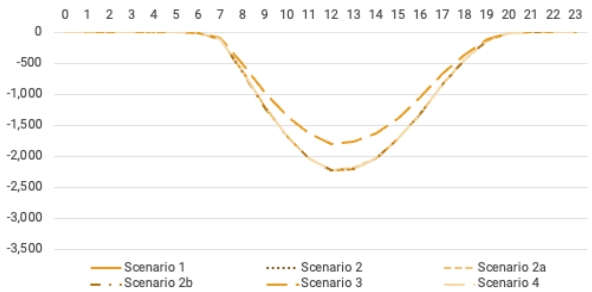
2030



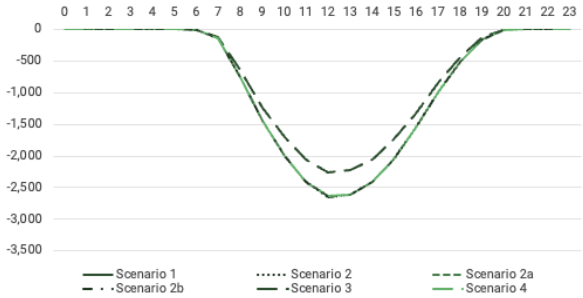
2035



2040



2045



2050

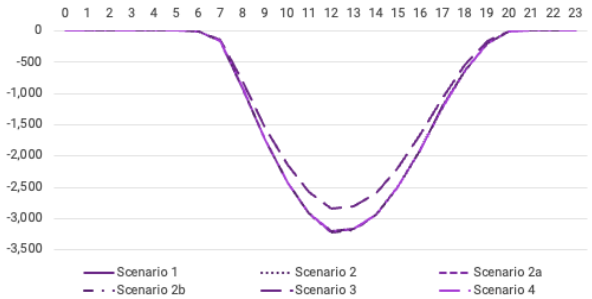
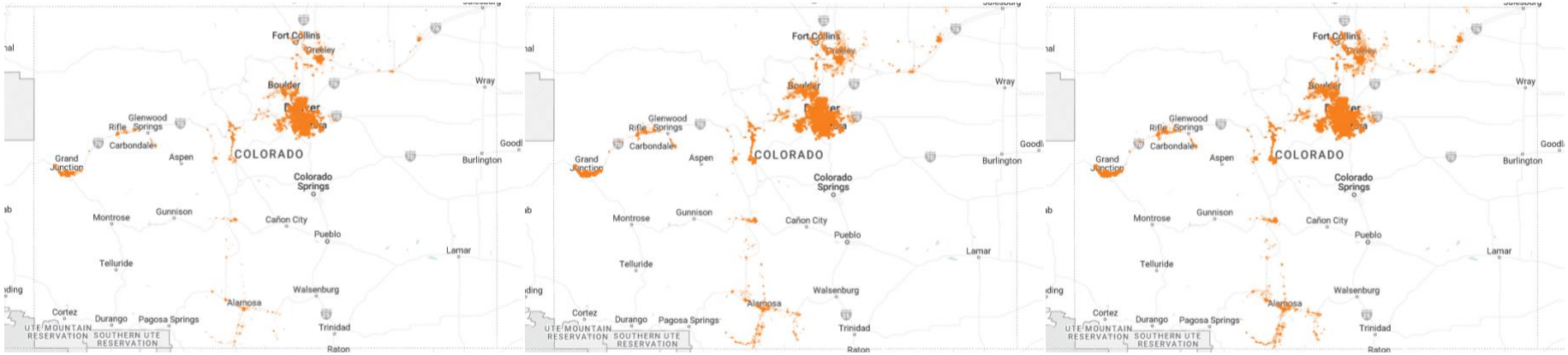


Figure F-10 shows the adoptions geographically. As these diagrams show, the adoptions early on (2025) are highly concentrated in the Denver metropolitan area, but over time there are more adoptions in the outlying areas and, in particular, Fort Collins.

Figure F-10: BTM PV system adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045

Scenario 2: Policy Aligned

2025 2035 2045



Scenario 3: Calibration

2025 2035 2045

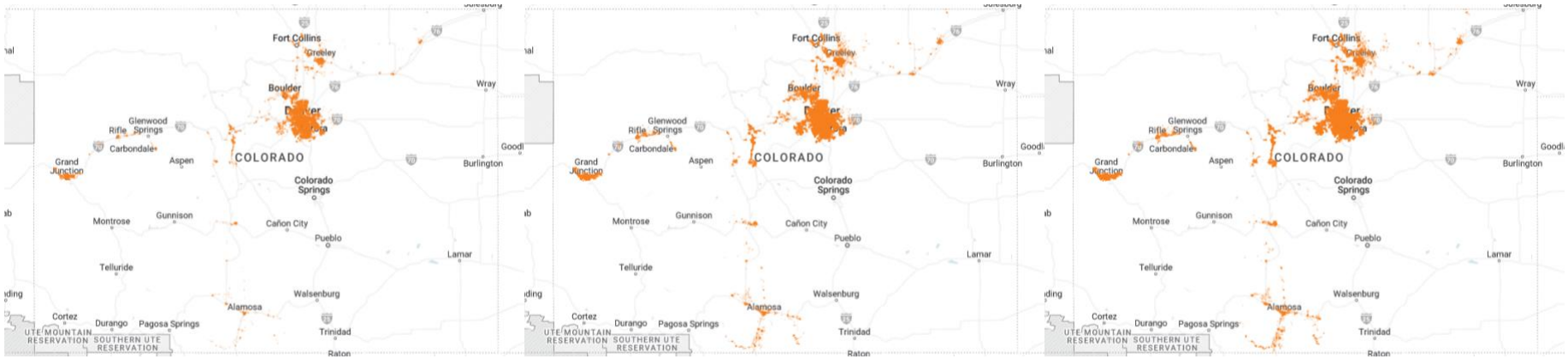


Figure F-11 and Figure F-12 are box and whisker charts showing the distribution of the contribution of BTM PV to the feeder coincident peak and noncoincident peaks, respectively. The x-axis shows the study year while the y-axis shows the range of capacity contribution (kW) of the DER to system peak load.

In Figure F-11, the variation of results among the scenarios is mostly driven by the hour of the system peak. For example, in 2050, the system peak hour ranges from 1700 to 2100 for all scenarios except 2a, which occurs at 0700 in February when some solar would be useful to mitigate the peak. This figure also shows little impact PV has on system peak for most scenarios, with the Calibration scenario showing the most benefit from PV early in the forecast period. Figure F-12 shows the contribution to feeder noncoincident peaks. Because the noncoincident peak hours vary there is more variability in the contribution to peak. These charts demonstrate more value to PV on mitigating feeder peaks, particularly for all scenarios except the Calibration scenario, which is consistent with the Calibration scenario targets for PV being much lower than the targets for the other scenarios. This shows, in part, that the peak hour for feeders is being driven by DER growth other than PV.

Figure F-11: Distribution of BTM PV at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala)



Figure F-12: Distribution of BTM PV at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

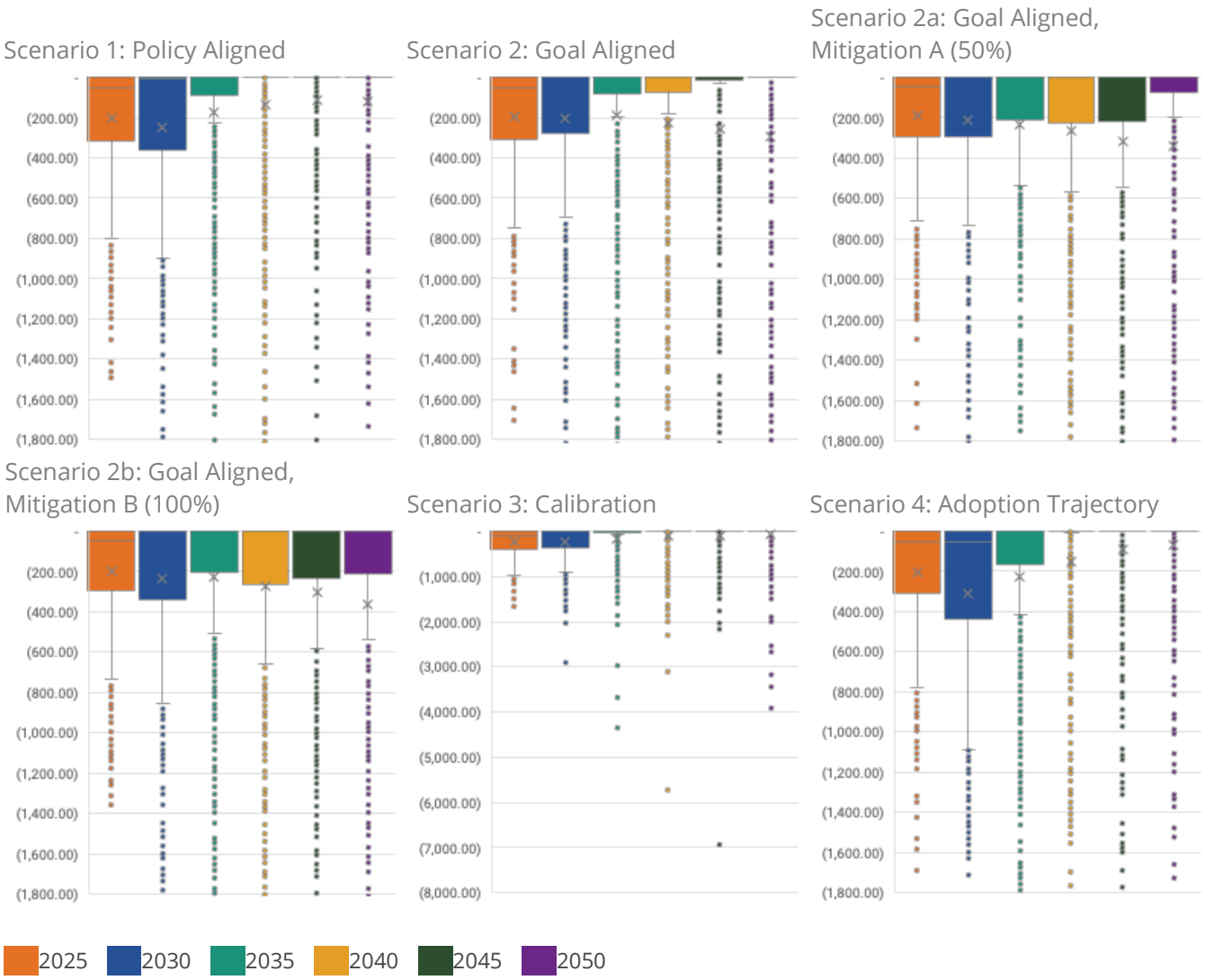
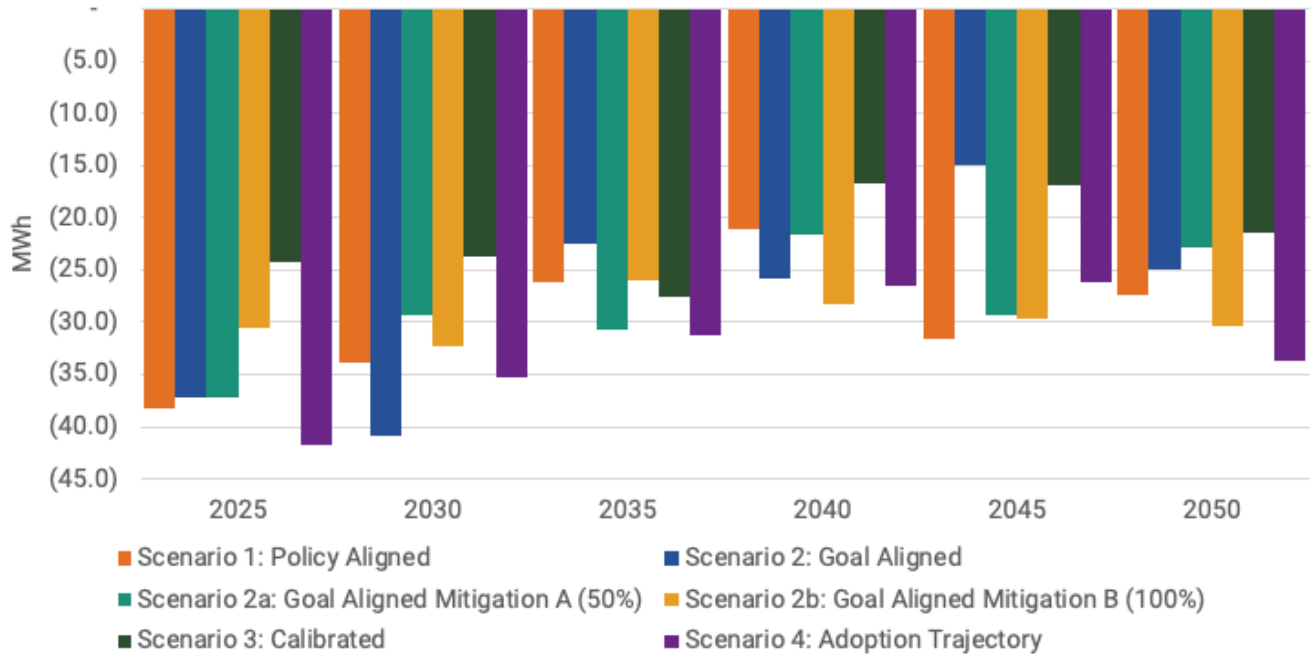


Figure F-13 shows the cumulative contribution of BTM PV generation to system peak for 2025, 2030, 2035, 2040, 2045, and 2050 by scenario, including losses. This figure shows the cumulative BTM PV in the system peak hour, and the general decline of the contribution to system peak over time.

Figure F-13: Cumulative contribution to system peak of BTM PV (MWh) by year and scenario: 2025-2050 (Source: Kevala)



In a series of box and whisker charts, Figure F-14 and Figure F-15 show the distribution of the size of BTM PV systems for residential and commercial customers by scenario for specific years.

Figure F-14: Distribution of the size of BTM residential PV systems (kW DC) by year and scenario: 2025-2050 (Source: Kevala)

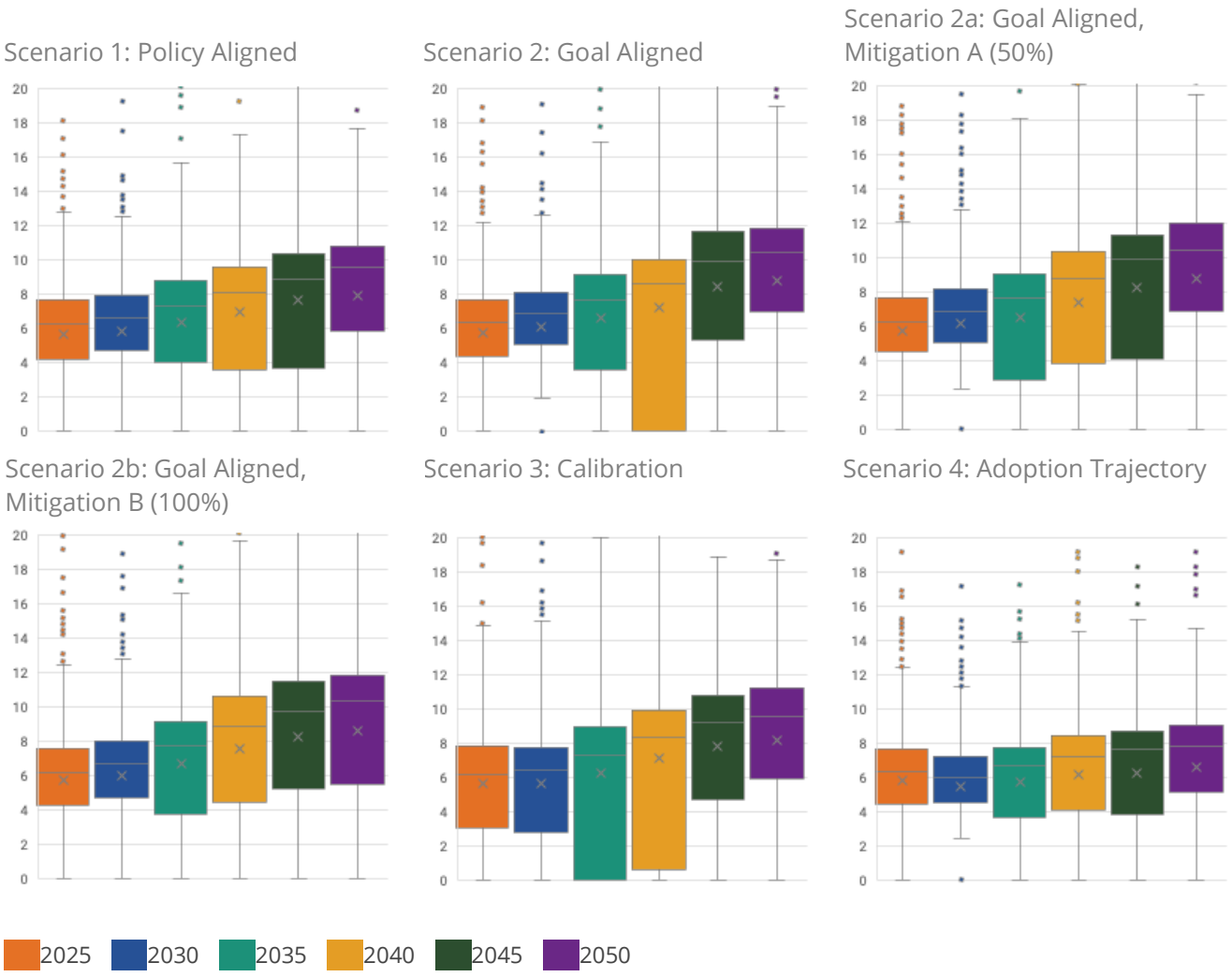


Figure F-15: Distribution of the size of BTM commercial PV systems (kW DC) by year and scenario: 2025-2050 (Source: Kevala)



The following are key findings from Kevala's analysis of the BTM PV results:

- BTM PV generation is expected to grow significantly in all scenarios, with a 12% CAGR for Scenario 3 (23% for Residential and 14% for C&I) and 14% in Scenarios 1, 2, and 4 (14% for both residential C&I).
- Despite significant BTM PV growth, the shift of the coincident peak hours from summer to winter reduces the benefits of PV in mitigating load growth, with the few exceptions in certain years.

F.2.2 CSG

The following figures show the results of the CSG adoptions by scenario and year. Figure F-16 shows the incremental and cumulative adoptions by scenario and year. These adoptions track

with the targets shown in Figure F-2. In a series of box and whisker charts (see Figure F-6 and the accompanying text for more detail on this type of chart), Figure F-17 shows the distribution of adoptions on feeders by scenario and year. The x-axis shows the study year while the y-axis shows the range of the number of CSG adoptions.

Figure F-16: Incremental and cumulative CSG adoptions by year and scenario: 2024-2050 (Source: Kevala)

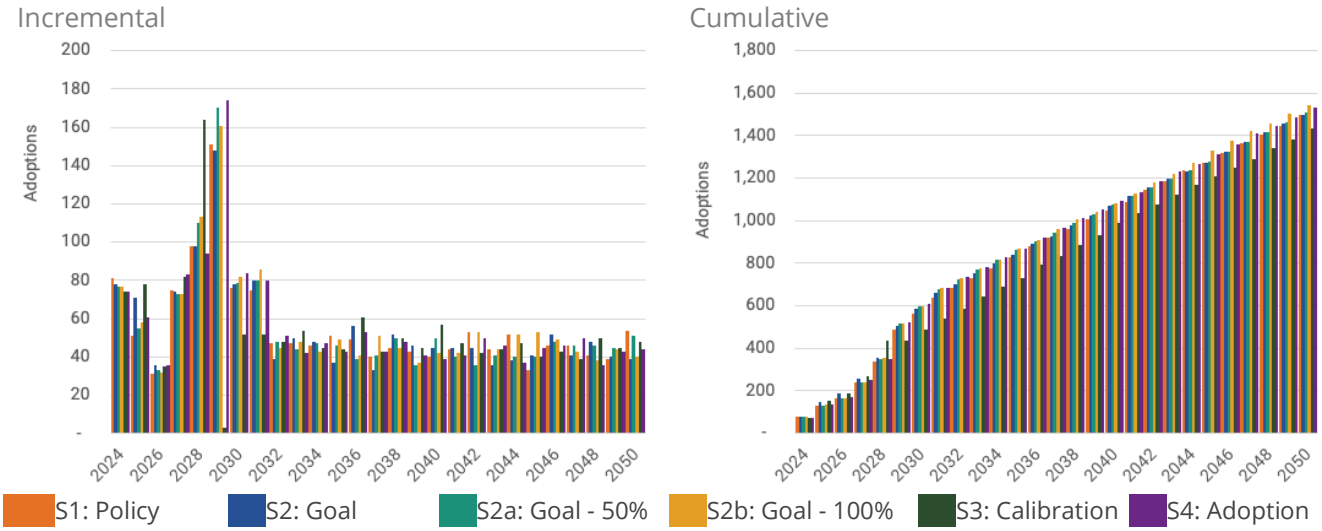


Figure F-17: Distribution of CSG adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)

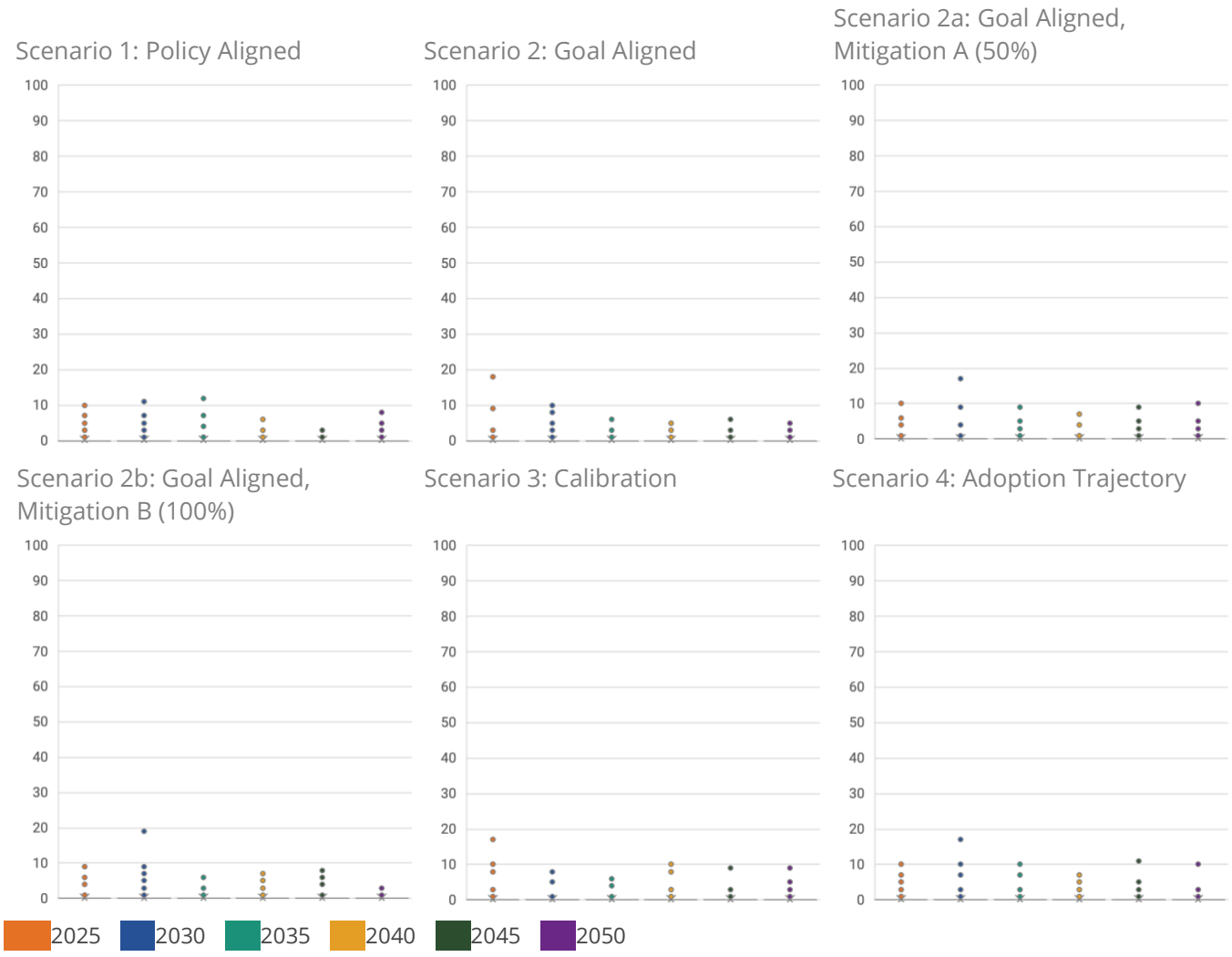
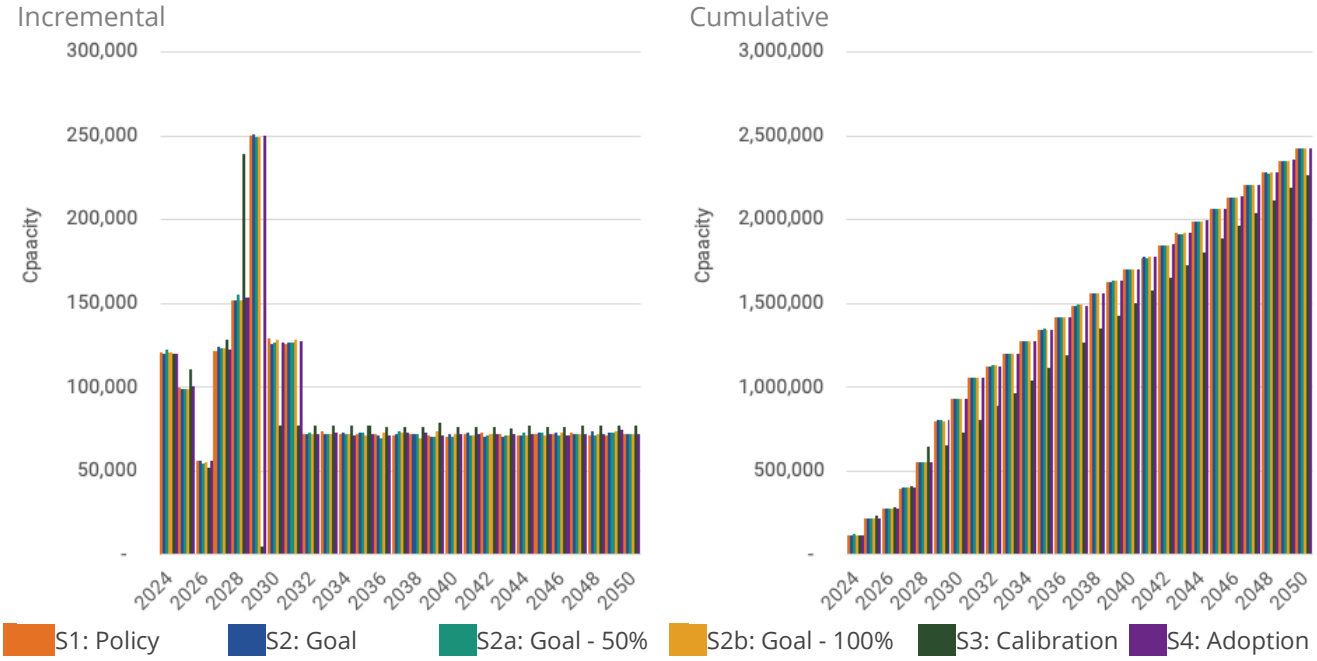


Figure F-18 shows the incremental cumulative capacity of CSG adoptions (kW DC).

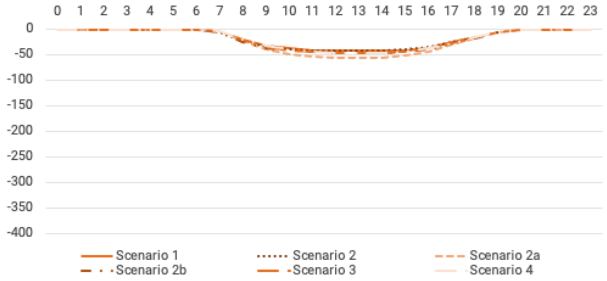
Figure F-18: Cumulative CSG capacity (kW DC) by scenario and year: 2024-2050 (Source: Kevala)



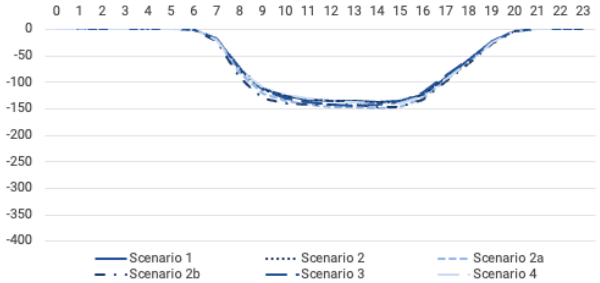
The CSG average load shapes for all the scenarios are shown in Figure F-19. These charts show the expected average generation behavior from CSG systems, and the slight differences among the scenarios over the years. The behavior shapes for CSG differ from BTM PV in that the BTM PV shapes are peakier while the CSG generation flattens out in the middle of the day, providing a more consistent generation profile but steeper ramping up and ramping down. Note these charts are showing average CSG generation at the premise and do not include losses.

Figure F-19: CSG average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala)

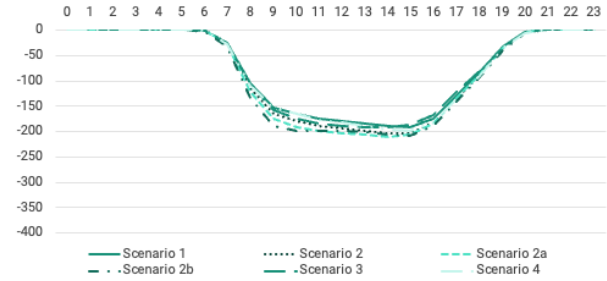
2025



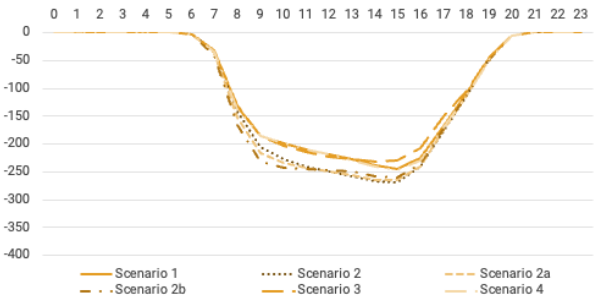
2030



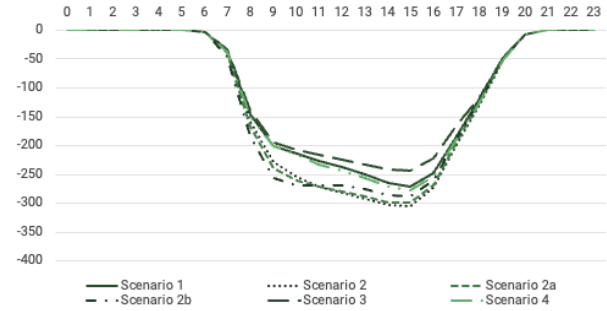
2035



2040



2045



2050

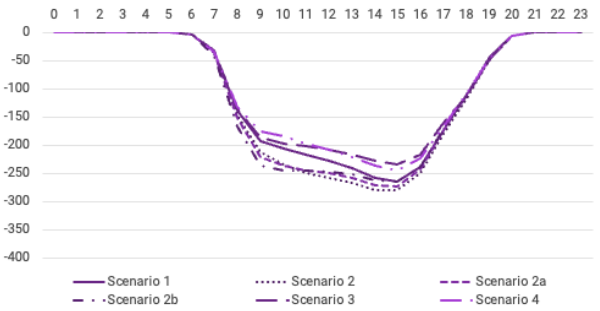
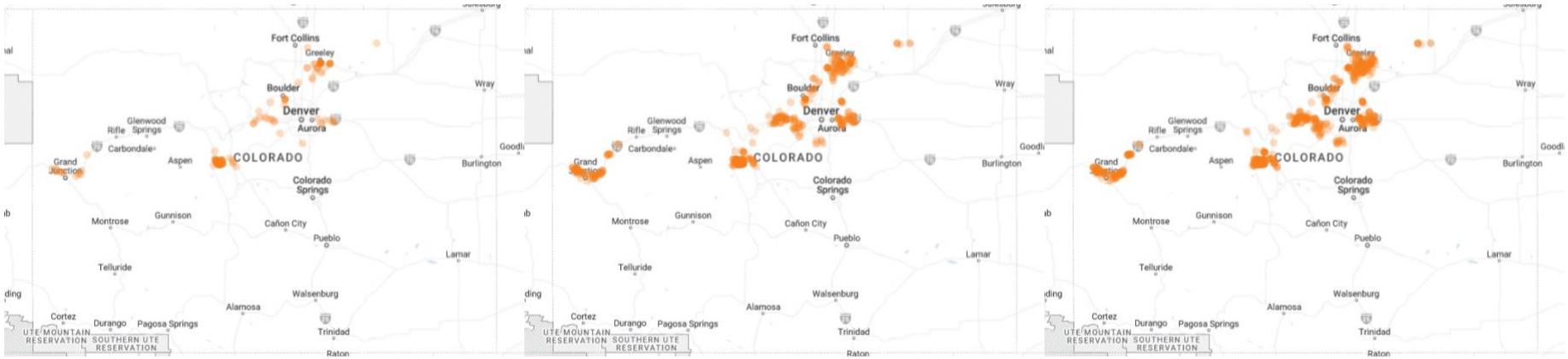


Figure F-20 shows the CSG the adoptions geographically. Similar to BTM PV, the adoptions early on (2025) are highly concentrated in the Denver metropolitan area, but over time there are more adoptions in the outlying areas and, in particular, Fort Collins.

Figure F-20: CSG system adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045

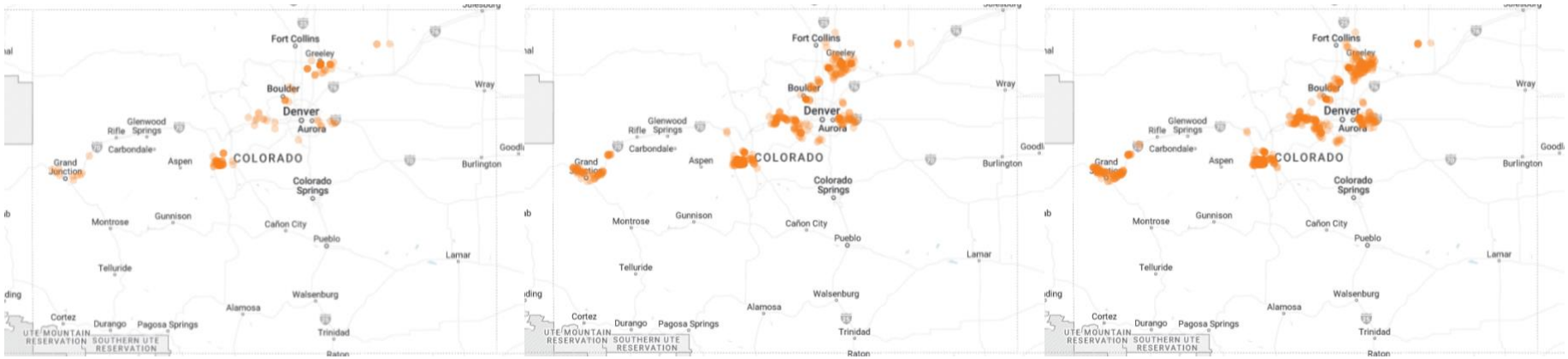
Scenario 2: Policy Aligned

2025 2035 2045



Scenario 3: Calibration

2025 2035 2045



Note: Larger dots correspond to larger CSG systems. Systems are 500 kW-5,000 kW.

Figure F-21 and Figure F-22 are box and whisker charts showing the distribution of the contribution of CSG to the feeder coincident peak and noncoincident peaks, respectively. The x-axis shows the study year while the y-axis shows the range of capacity contribution (kW) of the DER to peak load.

The charts in Figure F-21 show a higher level of contribution to peak than BTM PV, in part due to the shape of the behavior curves, and vary more among scenarios, with Scenario 2b showing the most impact from CSG on feeder coincident peaks. As Figure F-22 shows, the impact on individual feeders is greater but on few feeders. This further demonstrates the concentration of CSG on particular feeders.

Figure F-21: Distribution of CSG at the system peak (kW) by year and scenario: 2025-2050

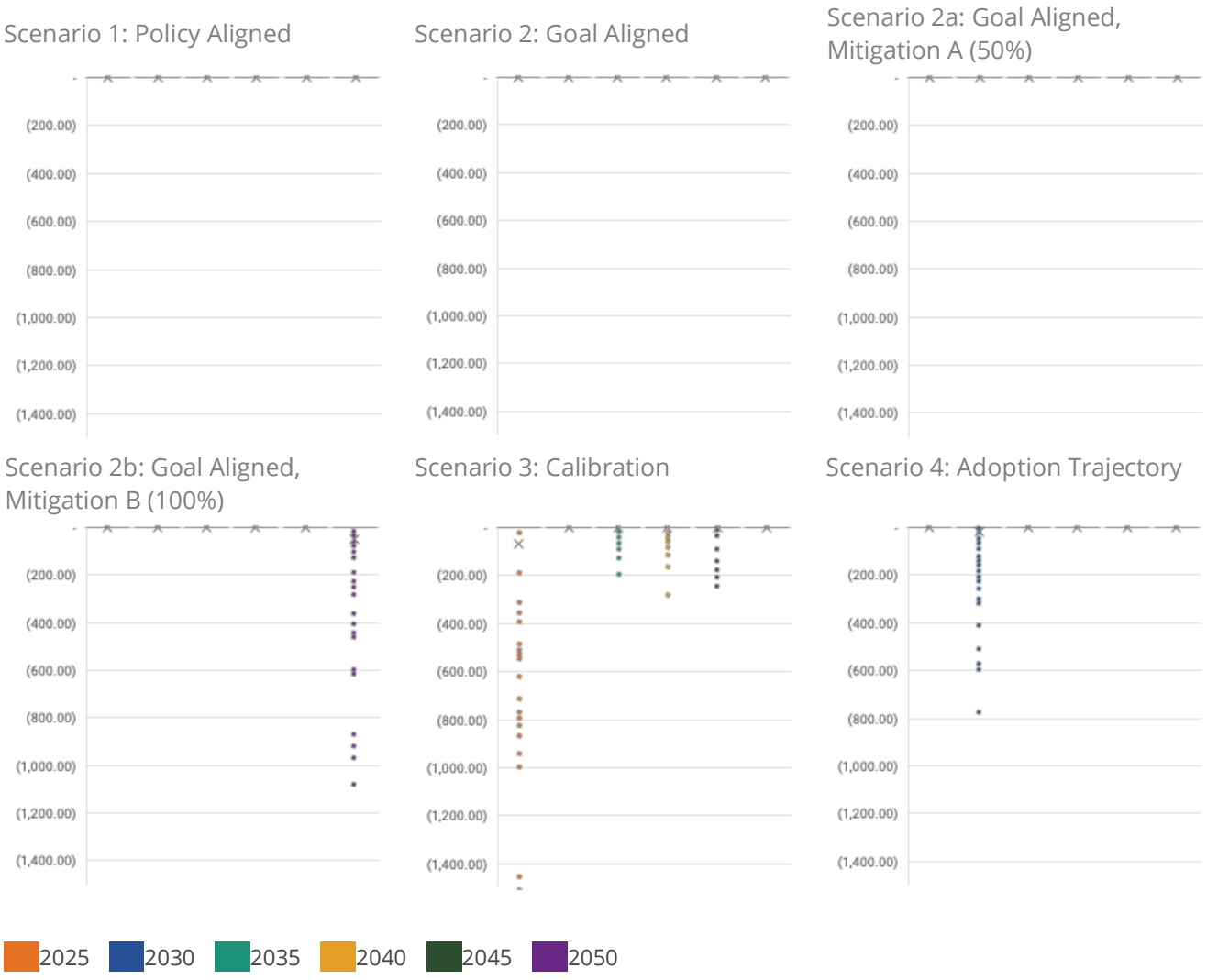
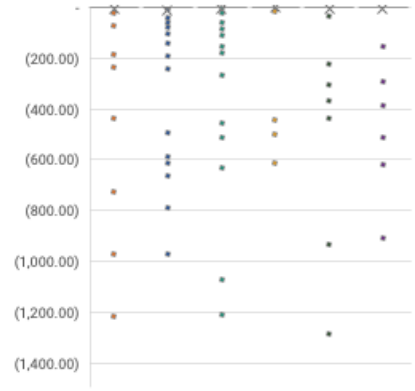
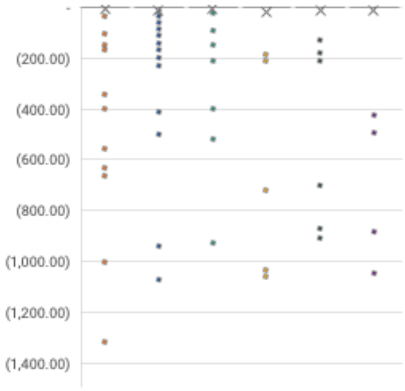


Figure F-22: Distribution of CSG at the feeder peak (kW) by year and scenario: 2025-2050

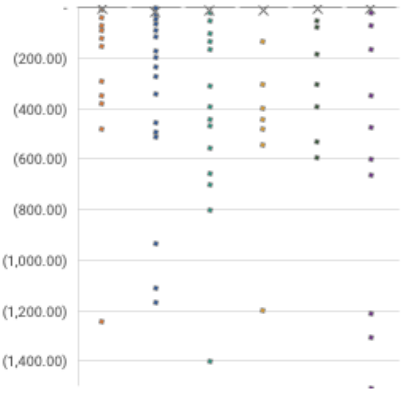
Scenario 1: Policy Aligned



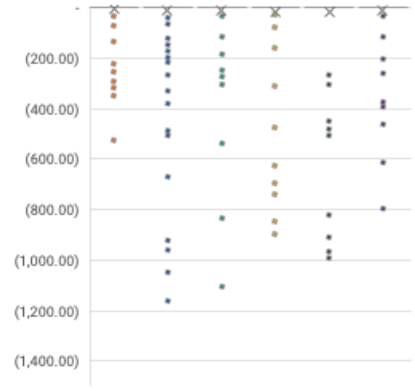
Scenario 2: Goal Aligned



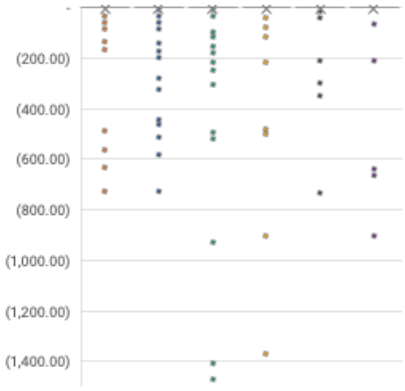
Scenario 2a: Goal Aligned, Mitigation A (50%)



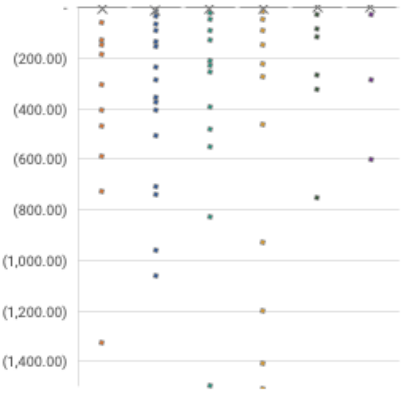
Scenario 2b: Goal Aligned, Mitigation B (100%)



Scenario 3: Calibration



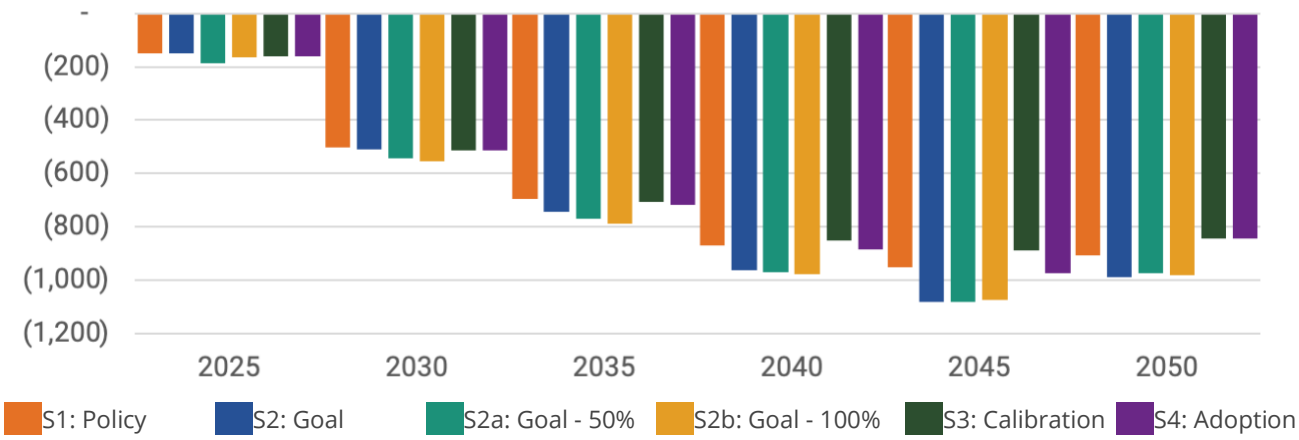
Scenario 4: Adoption Trajectory



2025 2030 2035 2040 2045 2050

Figure F-23 shows the cumulative energy from CSG for selected years by scenario.

Figure F-23: Cumulative energy (GWh) from CSG by year and scenario: 2025-2050 (Source: Kevala)



The following are key findings from Kevala's analysis of the CSG results:

- Due to the eligibility criteria for CSG sizing used in this study (see Appendix F.1.2), a high proportion of adoptions resulted in systems being clustered on a small number of feeders. This illustrates that, if the CSG adoption targets used in this study are realized, they will require significant coordination between developers and PSCo during the interconnection process; in many cases, meeting these targets will likely require significant capacity additions or more relaxed criteria around land area requirements and existence of buildings on premises, to realize their full generation potential.
- CSG adoption is significant but does not contribute to the decrease in the net load for the system peak hour.
- CSG generation does not have a significant impact on net load during system peak hours, particularly in the later years of the study. This is due to changing peak times driven by other DERs.

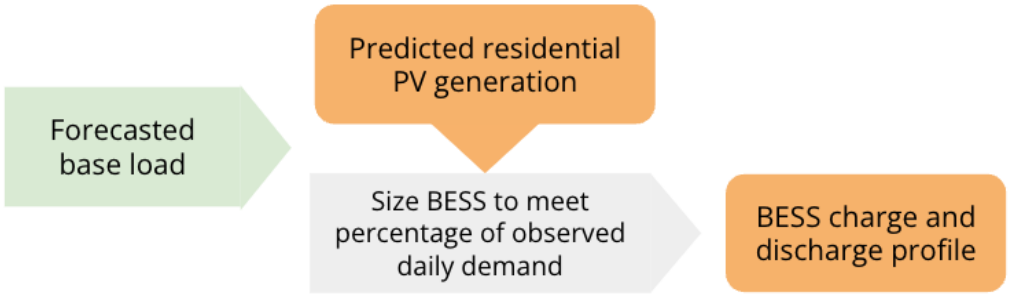
Appendix G. Residential Battery Energy Storage System Modeling Methodology and Additional Results

G.1 Approach

Kevala's approach required estimating the size, behavior, and adoption of behind-the-meter (BTM) residential battery energy storage systems (BESS). The residential BESS behavior and adoption models depended on the outputs of the PV module based on the understanding that most future residential BESS will be adopted and operated in conjunction with solar PV.

Given a service territory-level adoption forecast, the method predicted the most likely year-by-year BESS adoption dates, locations, and resulting 8760 (yearly hourly) charging and discharging behavior. Figure G-1 shows the flow of the residential BESS modeling.

Figure G-1: Flow diagram of BTM residential BESS modeling (Source: Kevala)



G.1.1 Sizing

Kevala's BTM residential BESS sizing model was based on the adoption of commercially available lithium-ion system options. The model analyzed a premise's load demand and PV generation when selecting the number and type of battery modules for potential installation. The battery specifications were adjusted for capacity (kWh) and power (kW) to align with standard commercially available batteries. Specifically, the BESS power rating was sized to meet a defined percentage of the maximum daily energy consumption, including PV generation and other distributed energy resources (DERs), to provide approximately 2 hours of backup energy at the BESS's peak power output. The model then selected a corresponding number of Tesla Powerwalls to meet or exceed this threshold. This most commonly equated to one Tesla Powerwall.

G.1.2 Behavior

Behavior for BESS is based on the assumption that residential customers will try to optimize PV self-consumption. Specifically, residential customers will choose to charge the BESS when the solar production is exceeding the premise energy use rather than exporting the excess generation to the grid. The residential customer will then consume the BESS energy after the solar production has ended for the day (e.g., after the sun goes down) until the charge in the BESS is diminished.

While this behavior is not explicitly modeled and structured to mitigate noncoincident peaks on individual assets, the timing of BESS discharge should fill the gap left by solar PV production toward the end of the day, at the beginning of traditional peak daily demand periods.

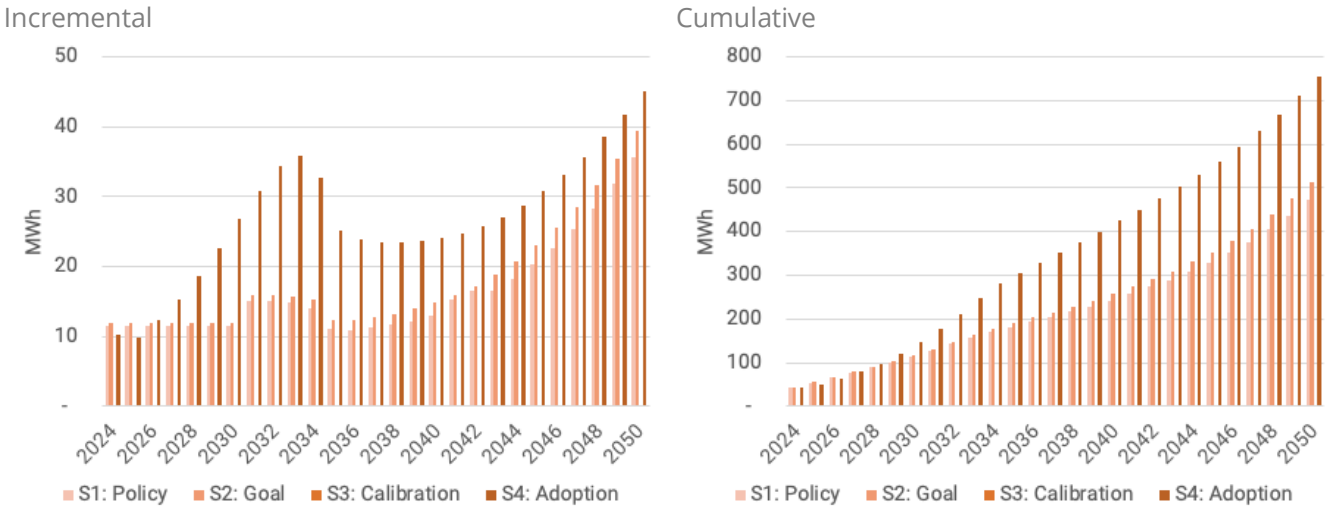
Once a residential BESS was sized for a premise, Kevala assumed that the BESS at these premises would be consistent with the optimization charge when PV generation was sufficient to produce net exports and would discharge when gross demand exceeded generation, constrained by the system's state-of-charge limits. Consequently, a residential BESS generally charged during the day and discharged in the early evening.

G.1.3 Adoption

Kevala assigned each premise an adoption propensity score proportional to the total yearly demand at the premise (i.e., the higher the total demand at the premise, the more likely it was to adopt BESS). The most important predictor of adoption was whether or not the premise had PV. The adoption model did not allow residential premises without PV to adopt BESS. Once adoption propensity scores were assigned for all eligible premises, Kevala ranked the eligible premises according to their score value and simulated adoption for each year in the forecast. Each year, adopting premises were selected one at a time from all eligible premises that had not already adopted BESS until the service territory's top-down yearly target capacity was reached.

Figure G-2 shows the incremental and cumulative BESS targets by scenario used for this study. PSCo only provided targets for residential systems. As these charts show, Scenario 3 (Calibration scenario) had no BESS adoption targets in all years. In the Policy Aligned and Goal Aligned scenarios, there is a mild increase in adoptions in the first 10 years and then a marked increase in adoptions in the last 10 years. For the Adoption Trajectory scenario, the pattern of adoption follows the same pattern seen for residential BTM PV adoption (see Figure F-2).

Figure G-2: Incremental and cumulative BESS target adoptions (MWh) by scenario and year: 2024-2050 (Sources: PSCo, Kevala)



The following are the key assumptions associated with BESS modeling:

- The BESS behavior model for residential customers assumed they are maximizing PV self-consumption; therefore, only residential customers with PV were allowed to adopt BESS. Kevala has observed in its proprietary interconnection data that few residential premises have BESS but not PV, so this was not included in the modeling methodology.
- BESS degradation and end-of-life removal/replacement were not included in the model for this study. This did result in an overestimation of performance over time. The financial impacts of BESS replacement on a given homeowner were not considered given that the initial payback period was also not included in the adoption model.
- BESS payback period was not used as a predictor in the adoption model because current payback periods are very long and may not be indicative of the future prices of BESS as the market matures.
- BESS configurations did not account for projected changes in storage technology options.
- Kevala assumed a standard 90% round-trip efficiency for all models.

G.2 Analysis and Results

As discussed previously, residential BESS adoption and behavior are directly linked to PV adoption and behavior. BESS results for all of these scenarios are discussed in more detail below.

Figure G-3 shows incremental (i.e., the number each year) and cumulative residential BESS adoptions by scenario and year. These adoptions track with the targets shown in Figure G-2. Figure G-4 shows the distribution of adoptions on feeders by scenario and year in a series of box and whisker charts (see Figure F-6 and the accompanying text for more detail on this type of

chart). The x-axis shows the study year while the y-axis shows the range of the number of BESS adoptions.

Figure G-3: Incremental and cumulative BESS adoptions by scenario and year: 2024-2050 (Source: Kevala)

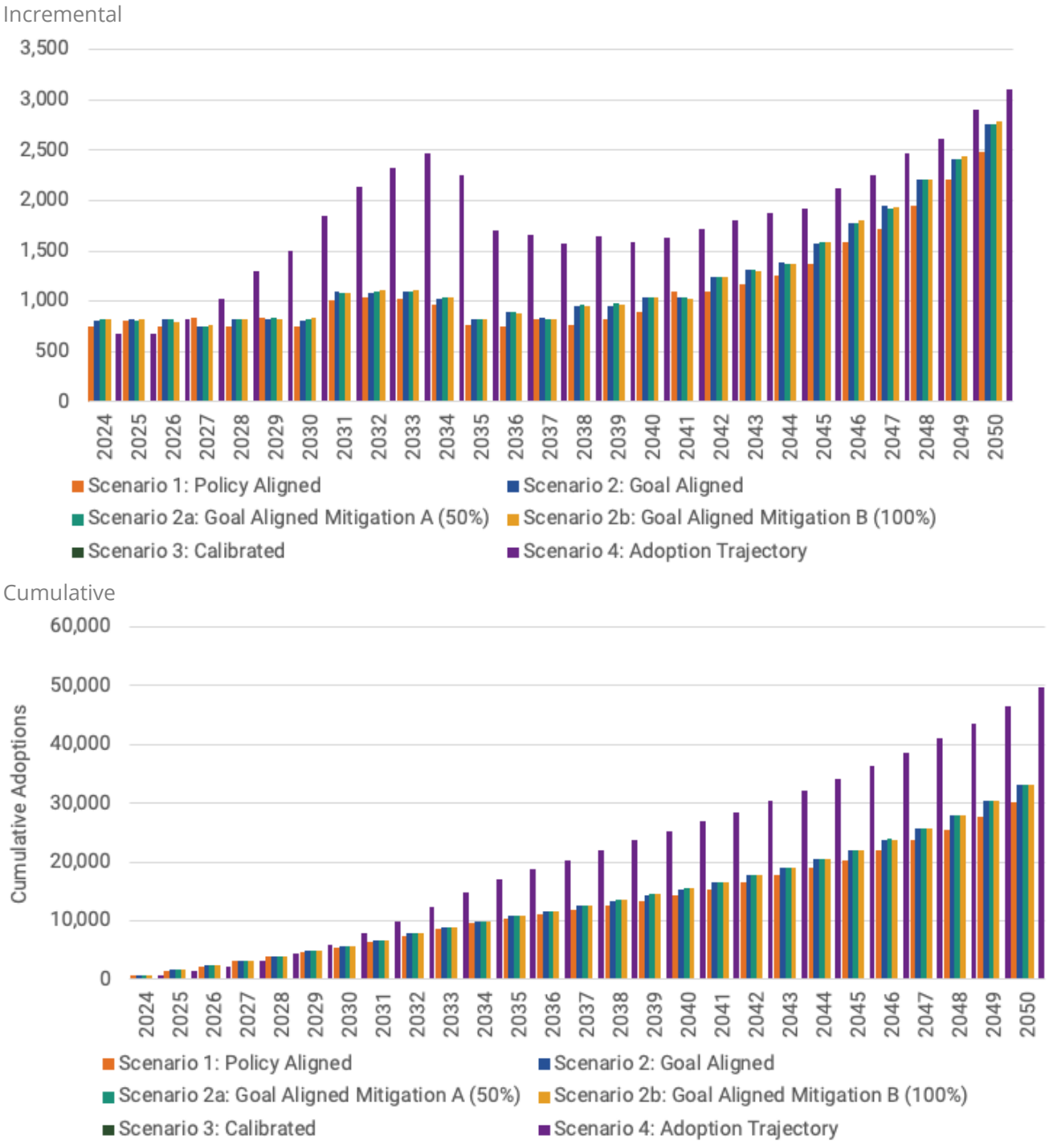


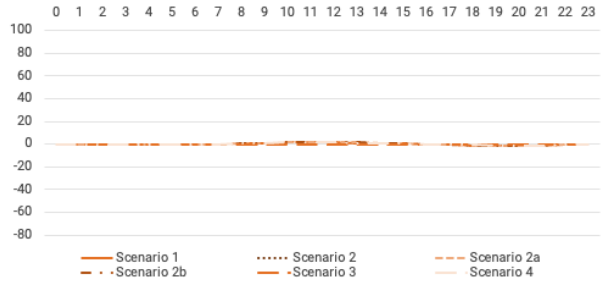
Figure G-4: Distribution of BESS adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)



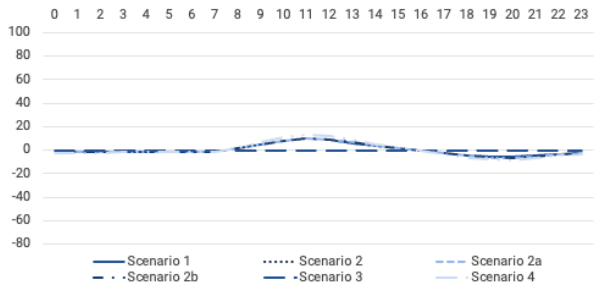
The residential BESS average load shapes for all the scenarios are shown in Figure G-5. These charts show the expected average generation behavior from residential BESS, and the differences among the scenarios over the years. The behavior shapes for residential BESS reflect the optimization assumption of charging when PV production is high and discharging as soon as the PV production stops. Specifically note the increase in residential BESS load during the day and reduction in evening. Note these charts are showing average residential BESS behavior at the premise and do not include losses.

Figure G-5: Residential BESS average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala)

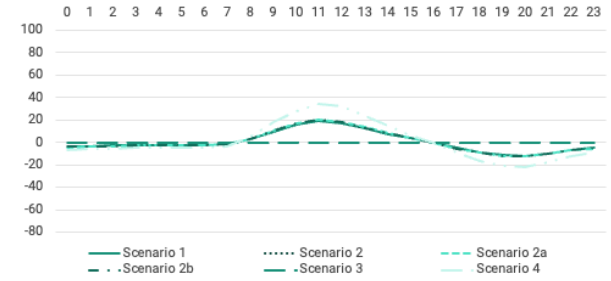
2025



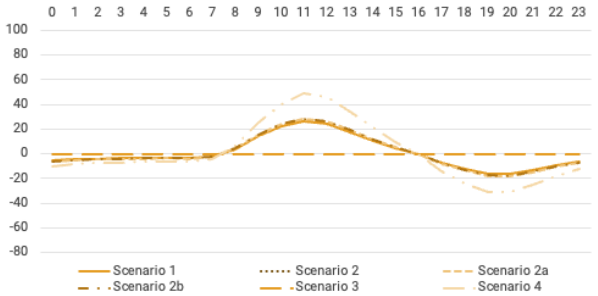
2030



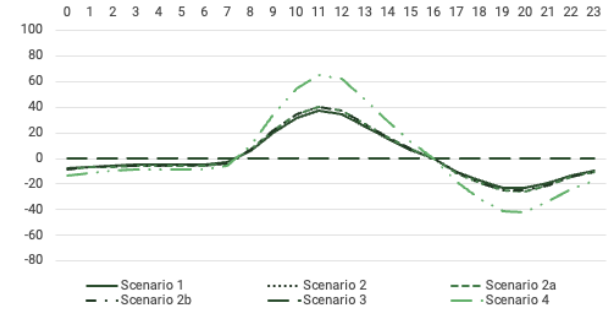
2035



2040



2045



2050

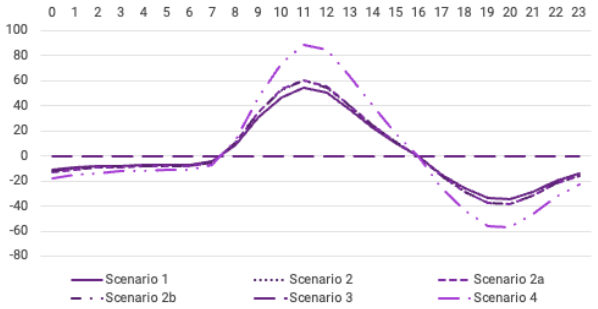


Figure G-6 shows the adoptions geographically. As these diagrams show, the adoptions early on (2025) are concentrated in the Denver metropolitan area, but over time there are more adoptions in the outlying areas. Note the Calibration scenario (Scenario 3) had no targets and thus no adoptions.

Figure G-6: BESS adoption across PSCo's service territory, Scenario 2 (Policy Aligned): 2025-2045 (Source: Kevala)

2025 2035 2045

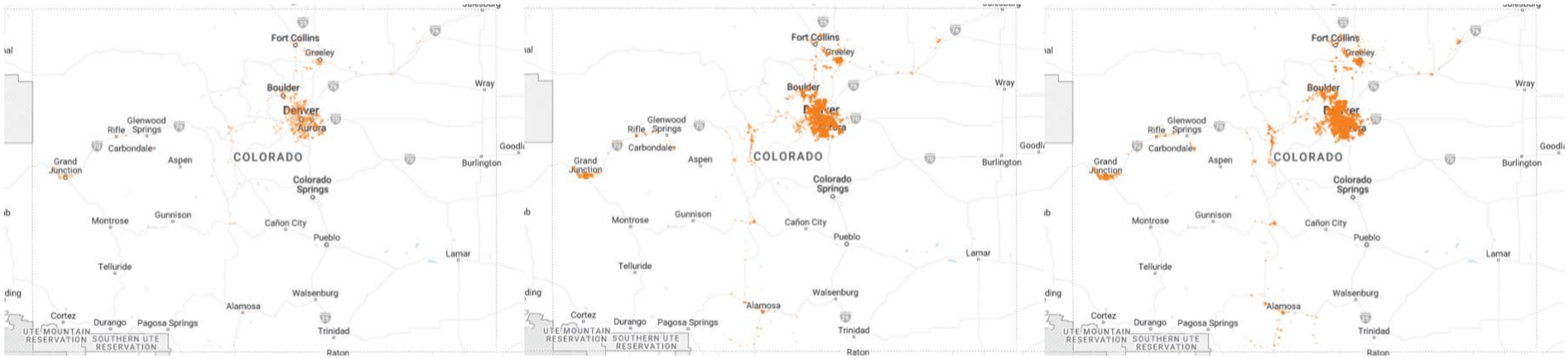


Figure G-7 and Figure G-8 are box and whisker charts showing the distribution of the contribution of residential BESS to the feeder coincident peak and noncoincident peaks, respectively. The x-axis shows the study year while the y-axis shows the range of capacity contribution (kW) of the DER to system peak load.

Figure G-7: Distribution of residential BESS at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

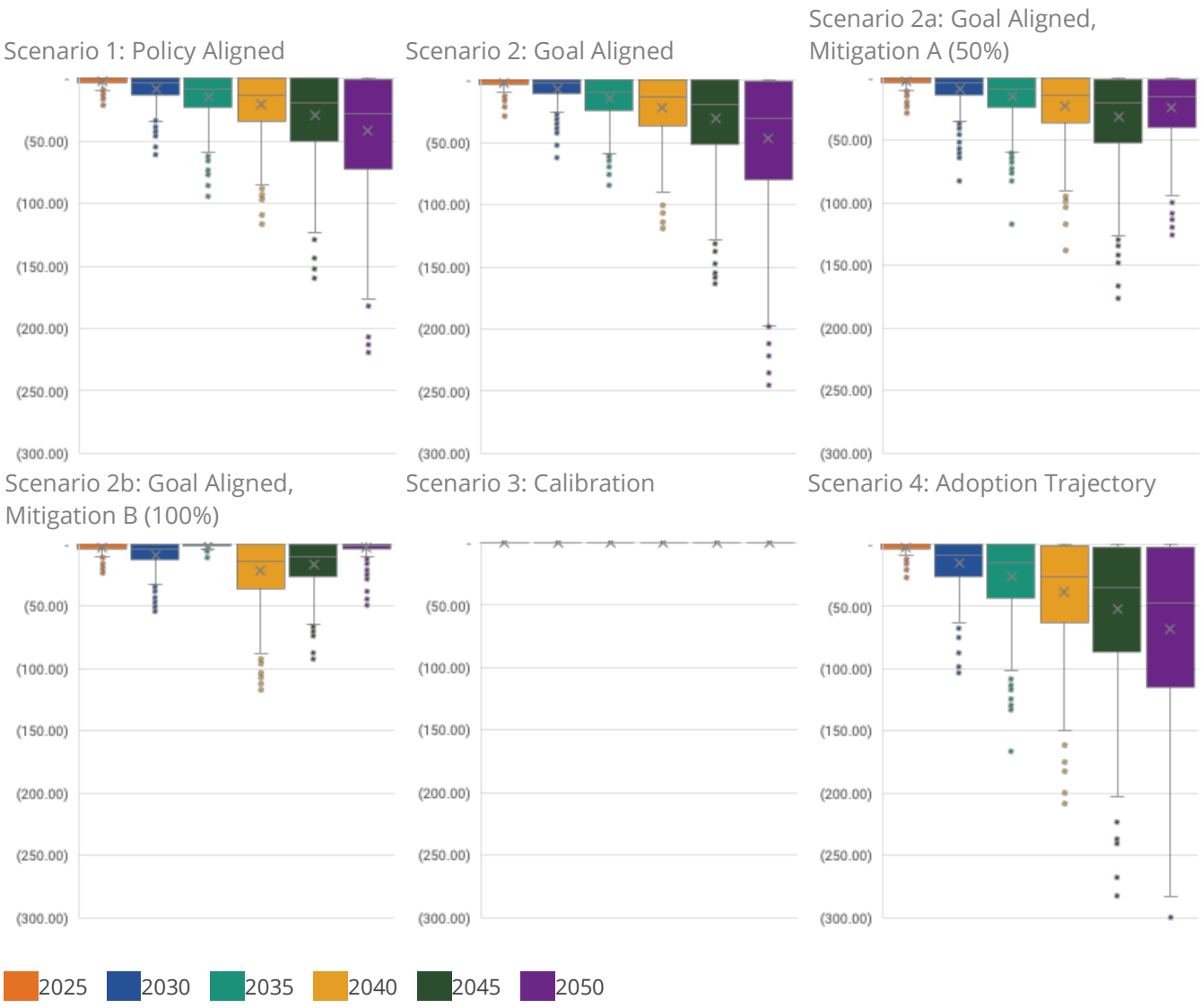


Figure G-8: Distribution of residential BESS at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

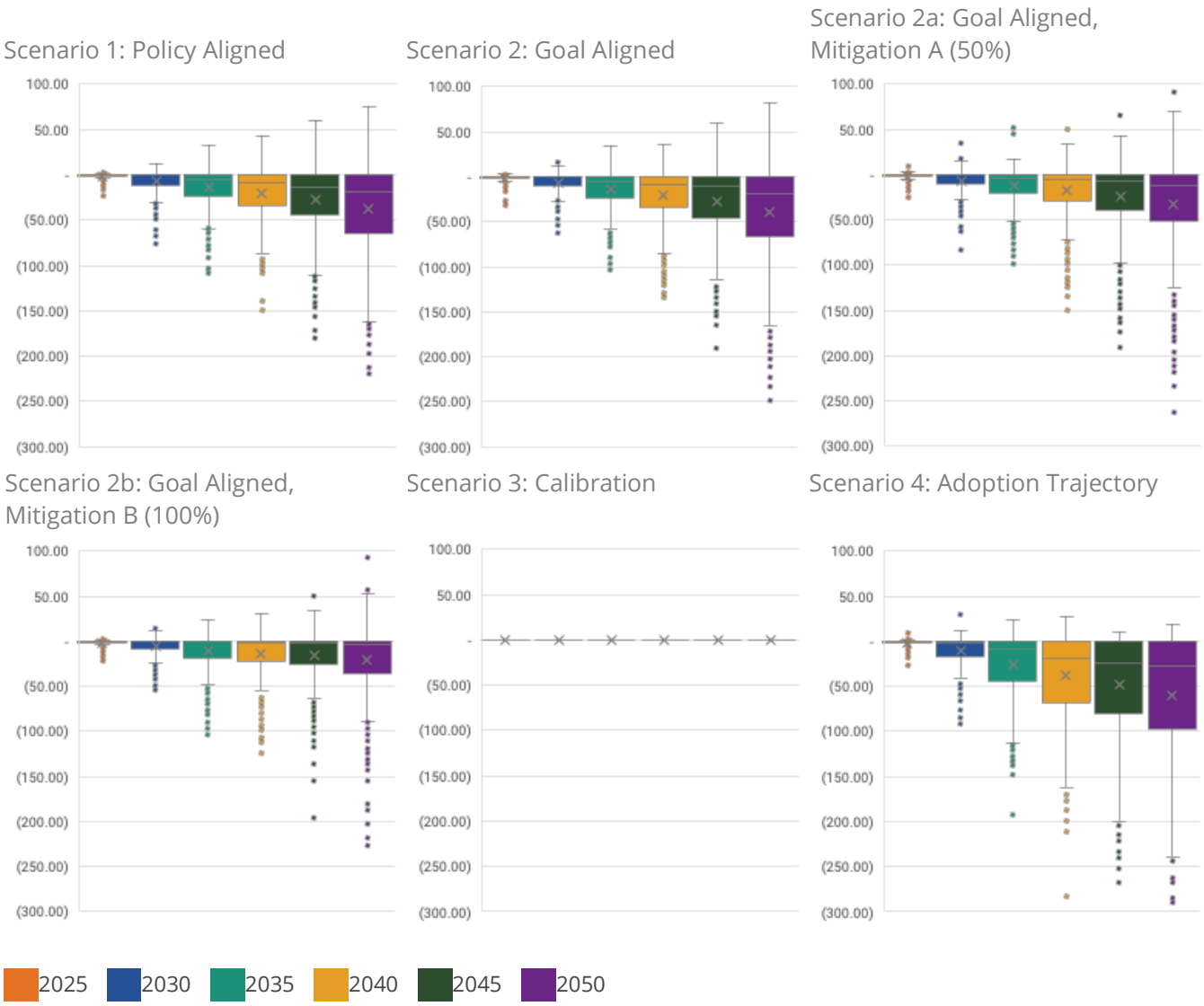
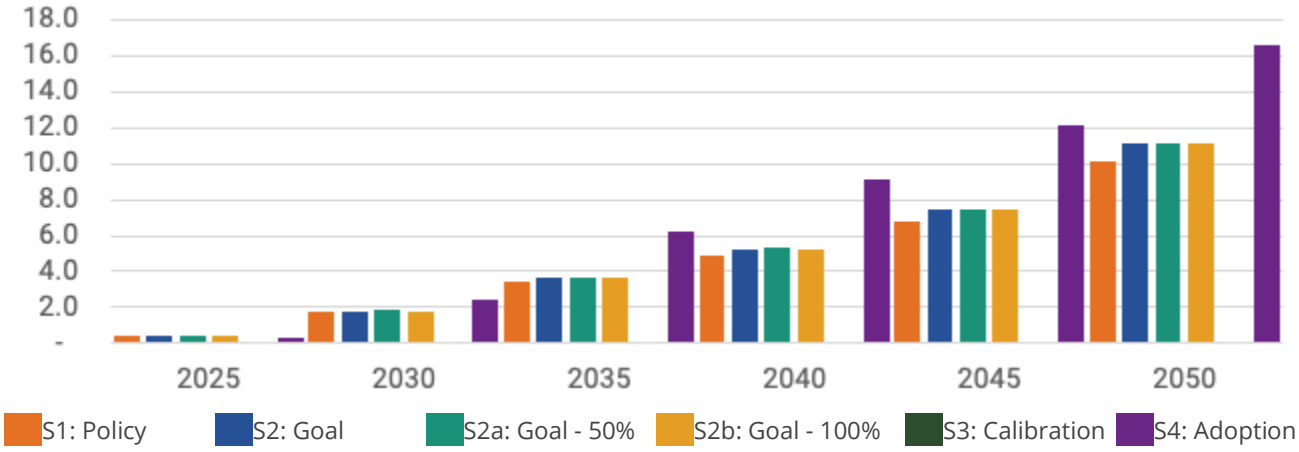


Figure G-9 shows the cumulative energy from residential BESS for selected years by scenario.

Figure G-9: Cumulative energy (GWh) from residential BESS by year and scenario: 2025-2050 (Source: Kevala)



The following are key findings from Kevala's analysis of the BESS results:

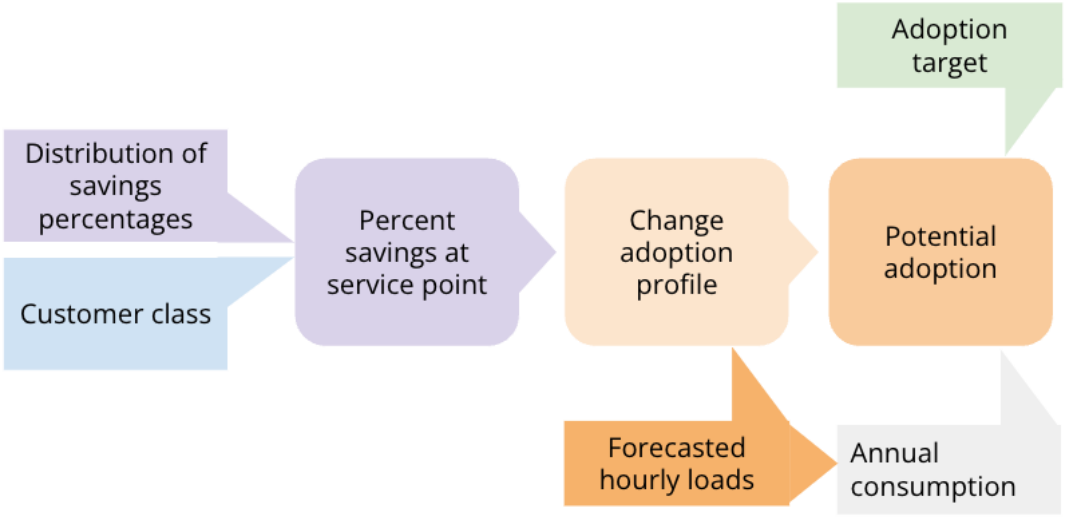
- Residential BESS adoptions follow solar PV because of the fundamental assumption that residential BESS is built with solar PV systems. As a result, for Policy Aligned and Goal Aligned scenarios, approximately 5% of premises with solar PV adopted BESS, while the Adoption Trajectory scenario resulted in approximately 15% of premises with solar PV adopting BESS.
- While minimal in size (300 kW) the pattern of residential BESS charging significantly assists in the decrease of system peak load.
- For feeder peaks, however, residential BESS appears to have both a negative and positive impact; the trend is toward decreasing (positive) feeder peaks.
- Due to losses between charging and discharging, residential BESS increases overall energy needs while potentially reducing peaks, so they could be an effective tool for managing distribution grid needs.

Appendix H. Energy Efficiency Modeling Methodology and Additional Results

H.1 Approach

Energy efficiency (EE) anticipates a reduction in total demand spread across a customer revenue class. Kevala estimated the size, behavior, and adoption of energy reduction for residential and commercial and industrial (C&I) customers across PSCo's service territory. Provided with cumulative gigawatt-hour targets by customer sector, the method predicted the most likely year-by-year EE adoption dates, locations, and resulting 8760 (yearly hourly) energy reductions. Figure H-1 shows the flow of the EE modeling.

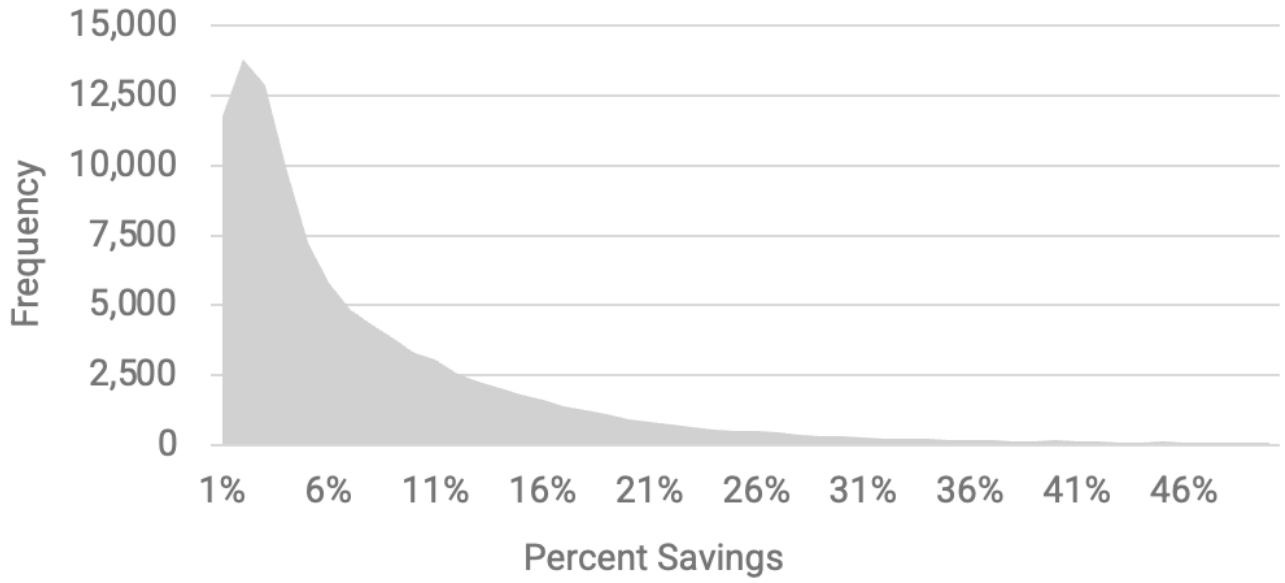
Figure H-1: EE modeling approach (Source: Kevala)



H.1.1 Sizing

Sizing was represented as the percent reduction in energy loads due to a customer installing EE measures or modifying their behaviors to reduce their energy use. The underlying assumption for this approach is that the impact of EE adoption on the grid is driven by the percentage of load reduced from energy efficiency rather than by a specific technology. To develop sizing at each premise, Kevala used its proprietary EE database that provides a distribution of potential percentage reduction in load. This database includes actual savings percentages from over 100,000 customers. Figure H-2 shows this distribution.

Figure H-2: Distribution of energy savings (Source: Kevala proprietary database)



H.1.2 Behavior

To forecast the potential demand modifier for a premise, Kevala applied a stochastic process to select the percent level of savings from the above distribution and applied that to the hourly base load forecast for the premise. By applying the percent savings to load, it reflects a step change in the energy use based on the historical use at the premise. It also reflects additional savings to weather-sensitive loads because hours of higher use resulting from weather show greater total savings relative to other lower-use hours.

H.1.3 Adoption

As with behavior, Kevala applied a stochastic process to identify which select premises in a customer revenue class adopted EE, continuing to select customers until the targeted level of savings were achieved. The PSCo-provided cumulative and incremental EE targets for the residential and C&I customer sectors are provided in Figure H-3 and Figure H-4.[52]

[52] Note that customers with existing electric resistance space heating who switch to heat pump heating ventilation, and air conditioning (HP HVAC) systems (a more efficient technology) were accounted for in these EE targets.

Figure H-3: Cumulative EE targets (MW) by customer sector and scenario: 2024-2050 (Sources: PSCo, Kevala)

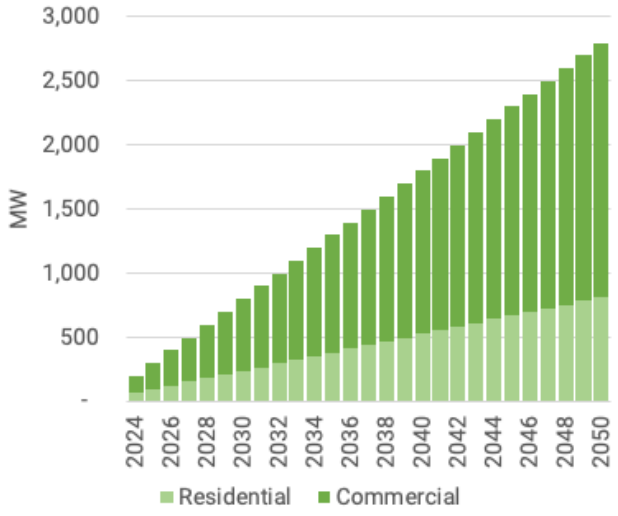
Scenario 1: Policy Aligned



Scenario 2: Goal Aligned



Scenario 3: Calibration

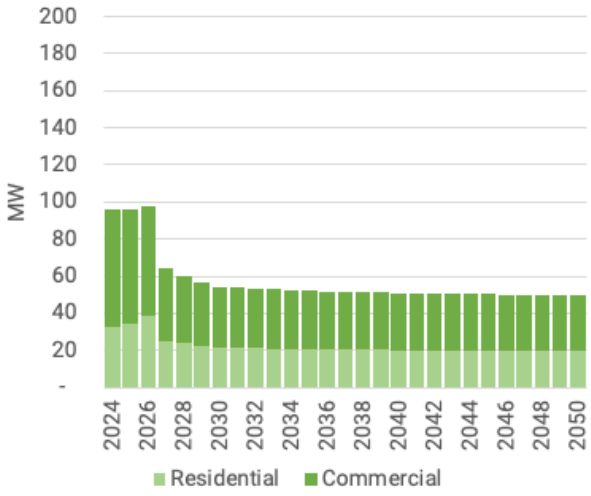


Scenario 4: Adoption Trajectory

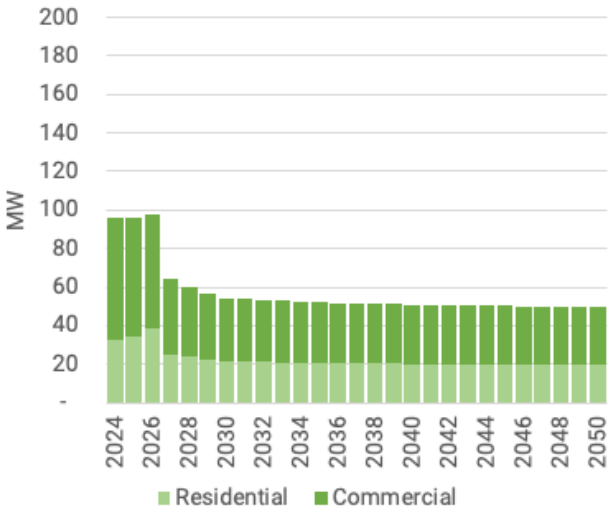


Figure H-4: Incremental EE targets (MW) by customer sector and scenario: 2024-2050 (Sources: PSCo, Kevala)

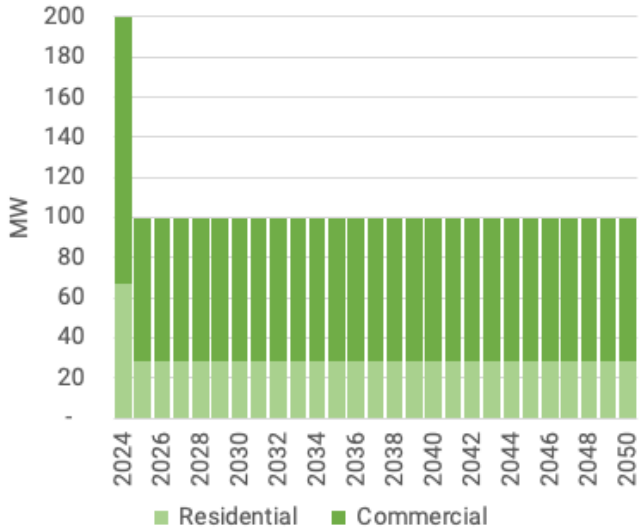
Scenario 1: Policy Aligned



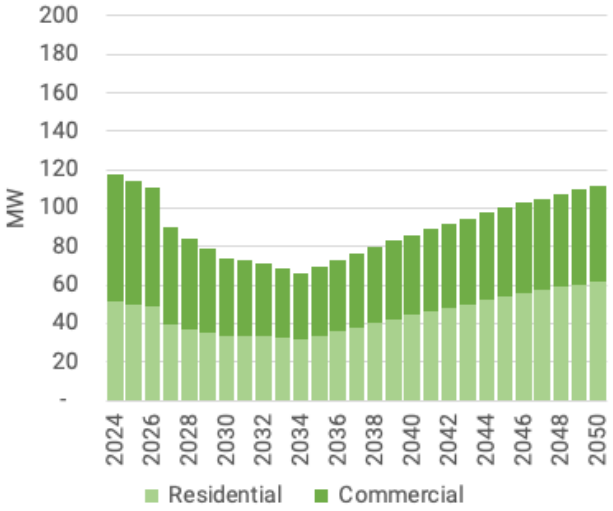
Scenario 2: Goal Aligned



Scenario 3: Calibration



Scenario 4: Adoption Trajectory



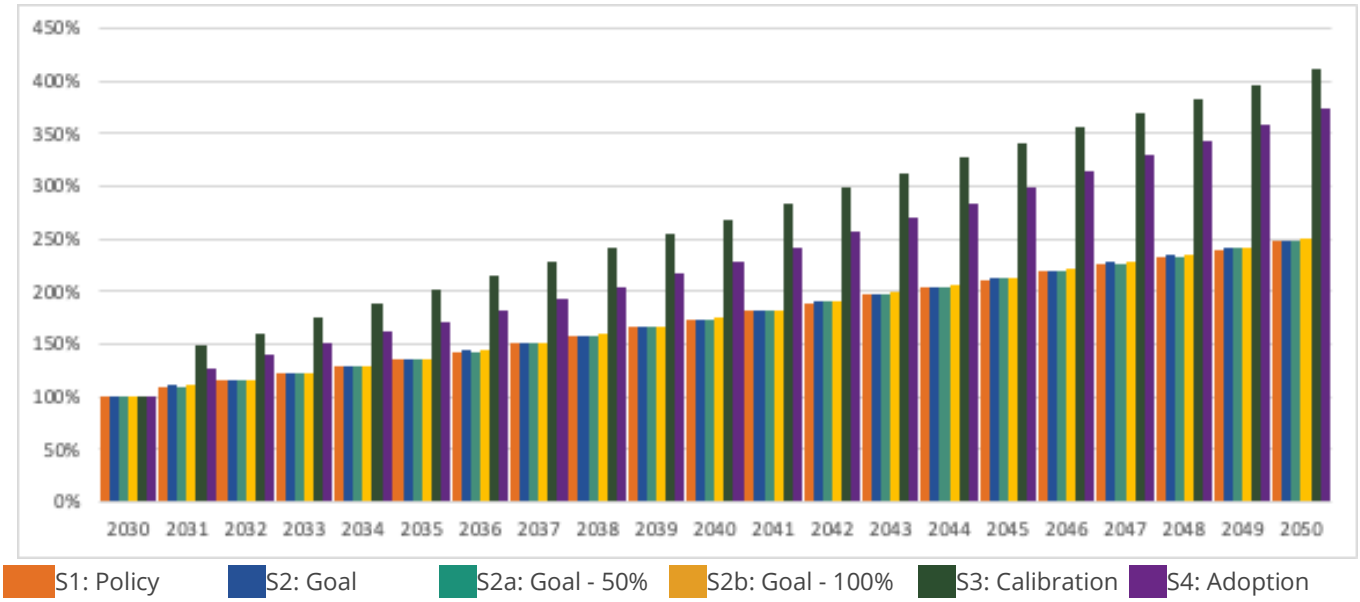
The following are the key assumptions associated with EE modeling:

- Once a premise adopts EE, it continues to participate throughout the forecast horizon, and the impacts of the adopted EE grow commensurate with PSCo's annual, scenario-based adoption target.
- Savings attributable to a premise are not highly dependent on demographics identifiable through Census data or other characteristics other than customer revenue class. As a

result, sizing and adoption are based on stochastic values that may vary from one scenario to another, and the seed value[53] is allowed to change.

- Percent savings potential and the distribution of these savings are consistent with the sample of percent savings in Kevala's proprietary database.
- Because customers have adopted EE relatively early across all scenarios (by end of 2030), Kevala assumed these same customers would continue to adopt EE over time and EE technologies would become more efficient, increasing the percent savings per premise. Specifically, shifting the average percent savings distribution shown in Figure H-2 to the right. To accomplish this, Kevala scaled the EE savings after 2030 across all EE adopters using the factors shown in Figure H-5. Note the factors differ by scenario to ensure each scenario's target is met.

Figure H-5: EE savings scalers by year and scenario (% of EE load) (Source: Kevala)



H.2 Analysis and Results

Figure H-6 shows the cumulative EE savings by customer sector, scenario, and year. These adoptions track with the targets shown in Figure H-3 and Figure H-4. Figure H-7 shows the distribution of adoptions on feeders by scenario and year in a series of box and whisker charts (see Figure F-6 and the accompanying text for more detail on this type of chart). The x-axis shows the study year while the y-axis shows the range of the number of EE adoptions.

[53] A seed value is a starting point for generating masked values.

Figure H-6: Cumulative EE energy savings by customer sector and scenario (kWh): 2024-2050 (Source: Kevala)

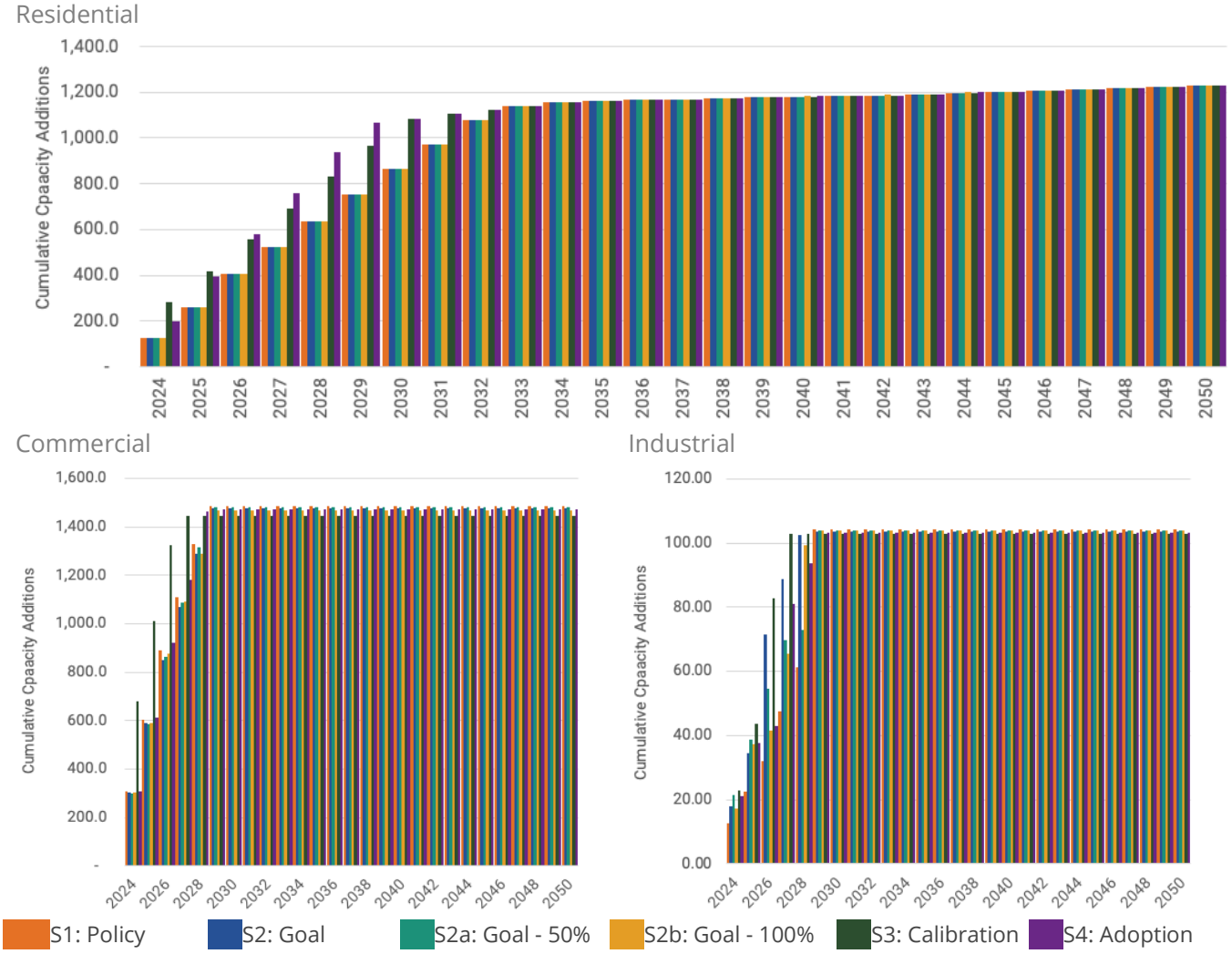
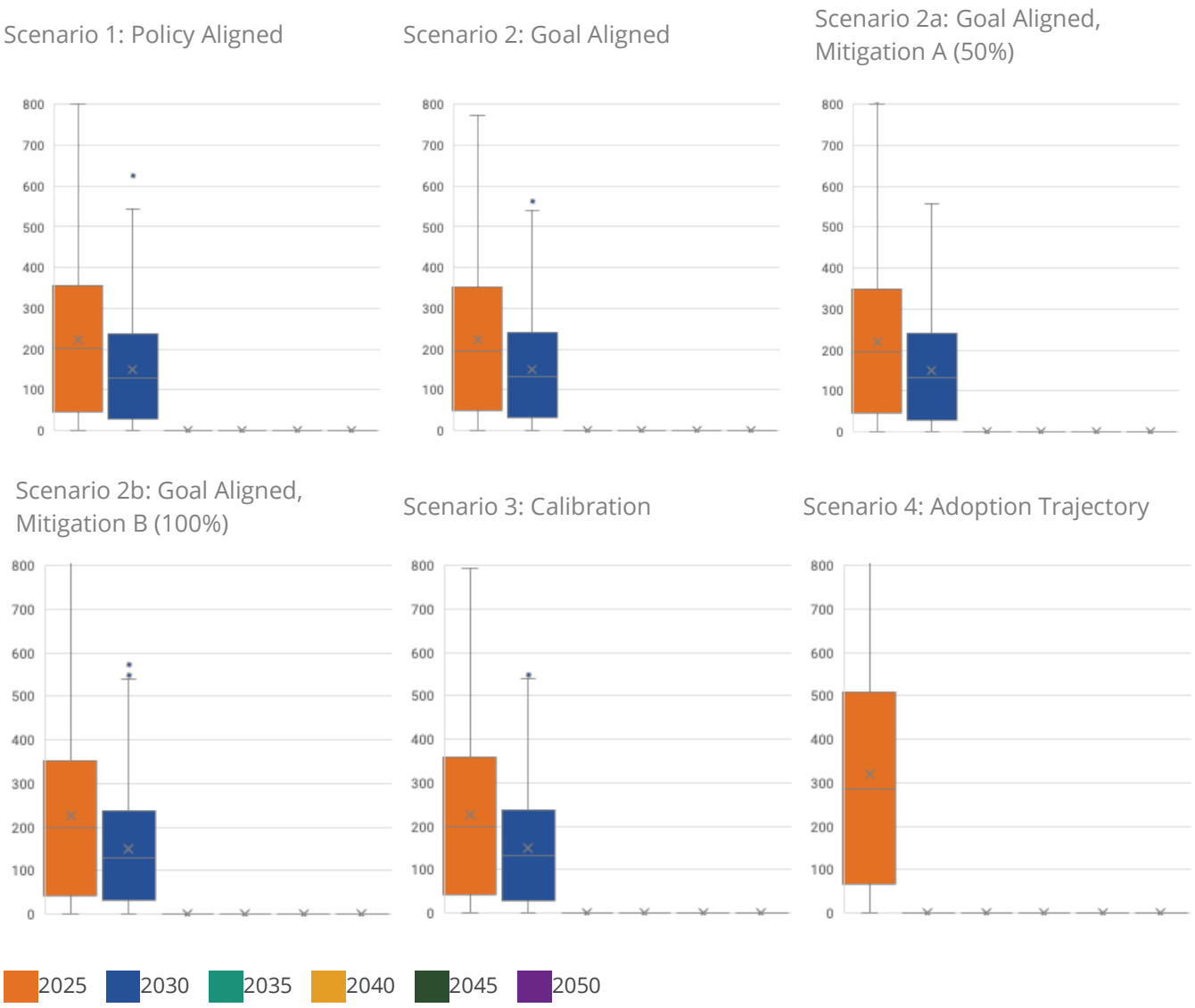


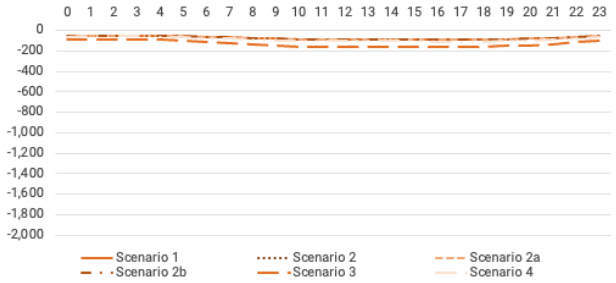
Figure H-7: Distribution of EE adoptions per feeder by year and scenario: 2024-2050 (Source: Kevala)



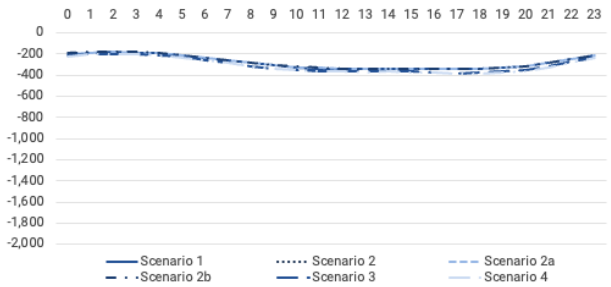
The EE average load shapes for all the scenarios are shown in Figure H-8. These charts show the expected average generation behavior from EE, and the differences among the scenarios over the years. The behavior shapes for EE follow the shape of base load because the EE savings is a percent savings that is applied to all hours of the premise's base load. The changes across years are due to the increased level of EE adoption. Note these charts are showing average EE load at the premise and do not include losses.

Figure H-8: EE average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala)

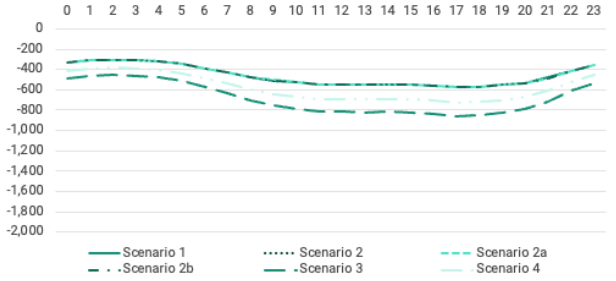
2025



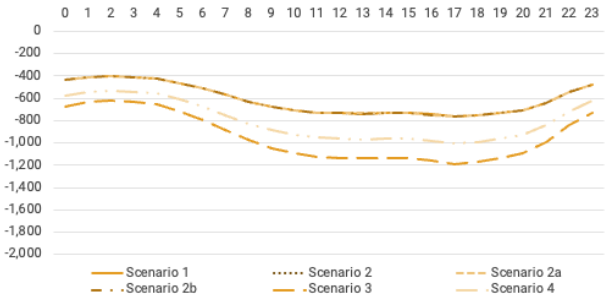
2030



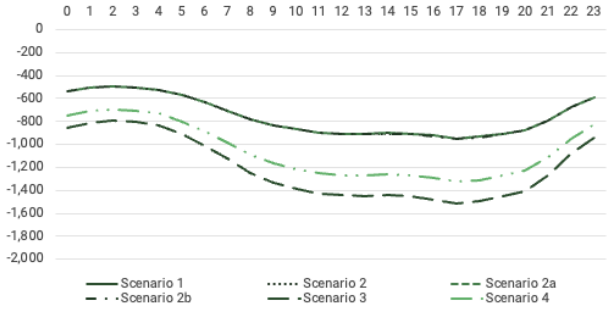
2035



2040



2045



2050

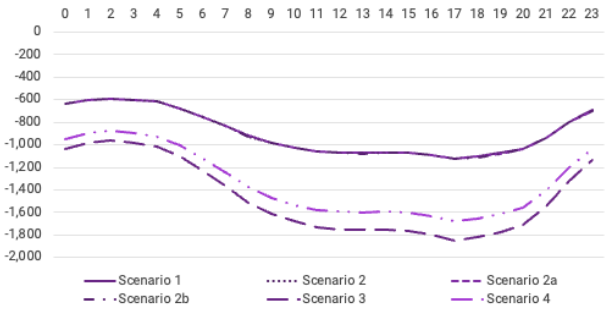
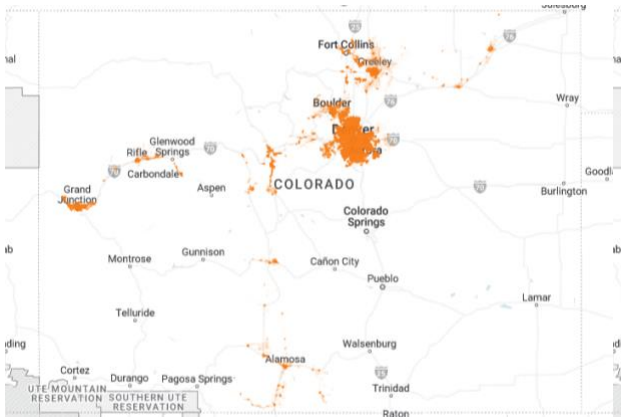


Figure H-9 shows the adoptions geographically.

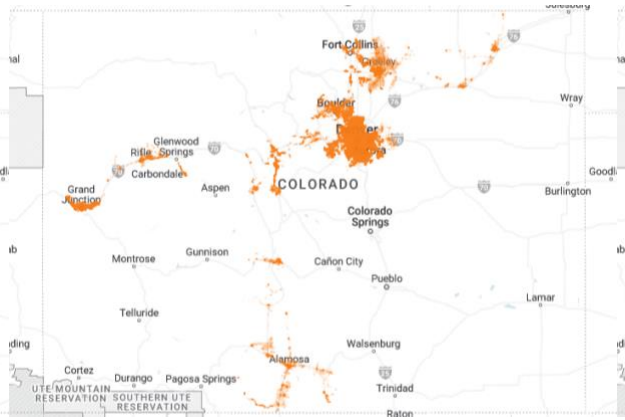
Figure H-9: EE adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 (Source: Kevala)

Scenario 2: Policy Aligned

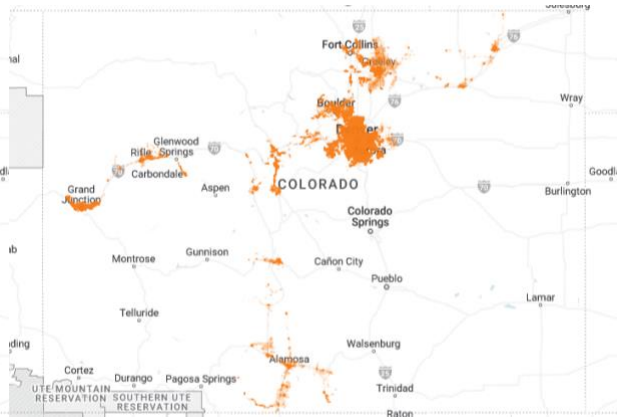
2025



2035

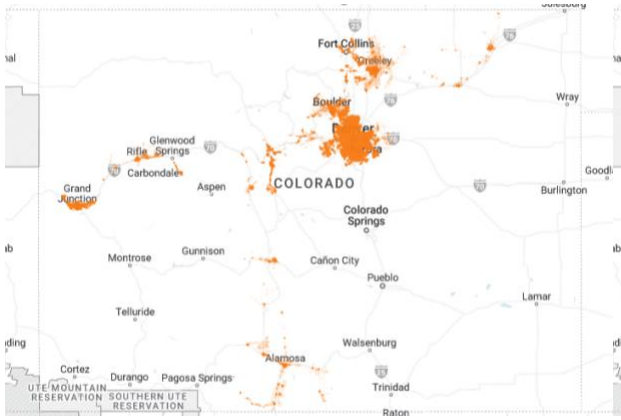


2045

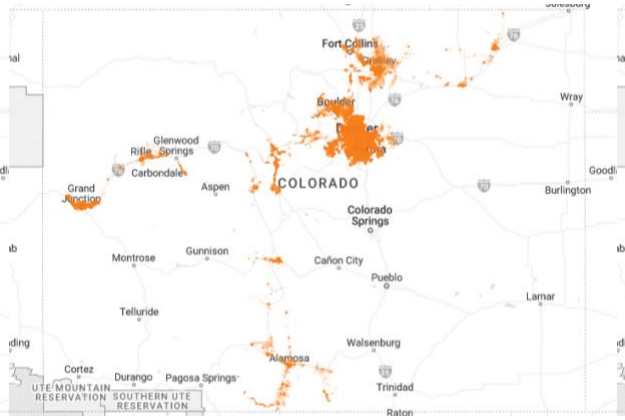


Scenario 3: Calibration

2025



2035



2045

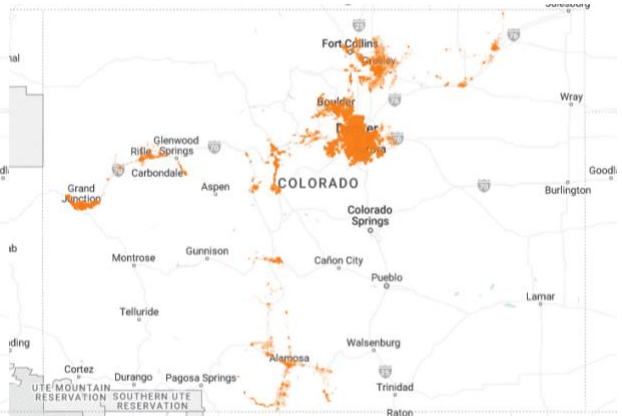
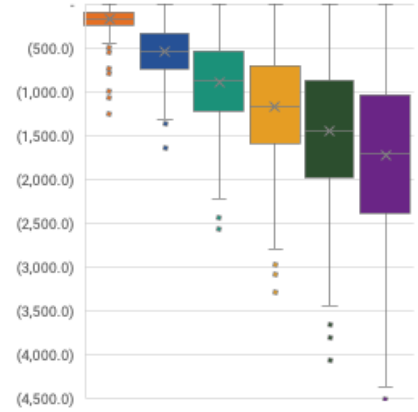


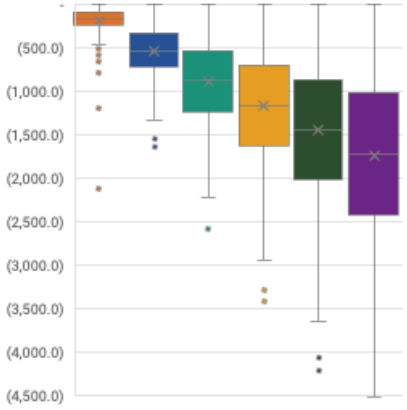
Figure H-10 and Figure H-11 are box and whisker charts showing the distribution of the contribution of EE to the feeder coincident peak and noncoincident peaks, respectively. The x-axis shows the study year while the y-axis shows the range of capacity contribution (kW) of the DER to system peak load.

Figure H-10: Distribution of EE at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

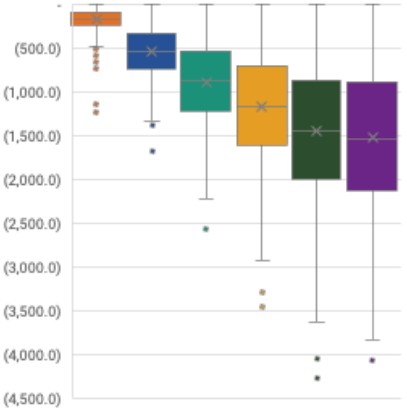
Scenario 1: Policy Aligned



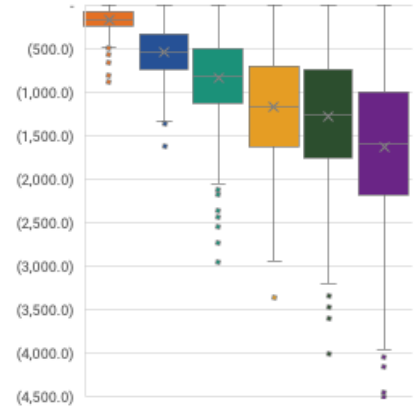
Scenario 2: Goal Aligned



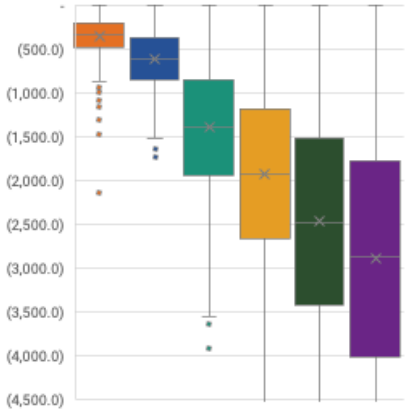
Scenario 2a: Goal Aligned, Mitigation A (50%)



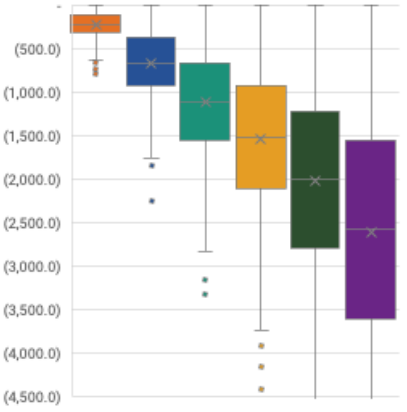
Scenario 2b: Goal Aligned, Mitigation B (100%)



Scenario 3: Calibration



Scenario 4: Adoption Trajectory



2025 2030 2035 2040 2045 2050

Figure H-11: Distribution of EE at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

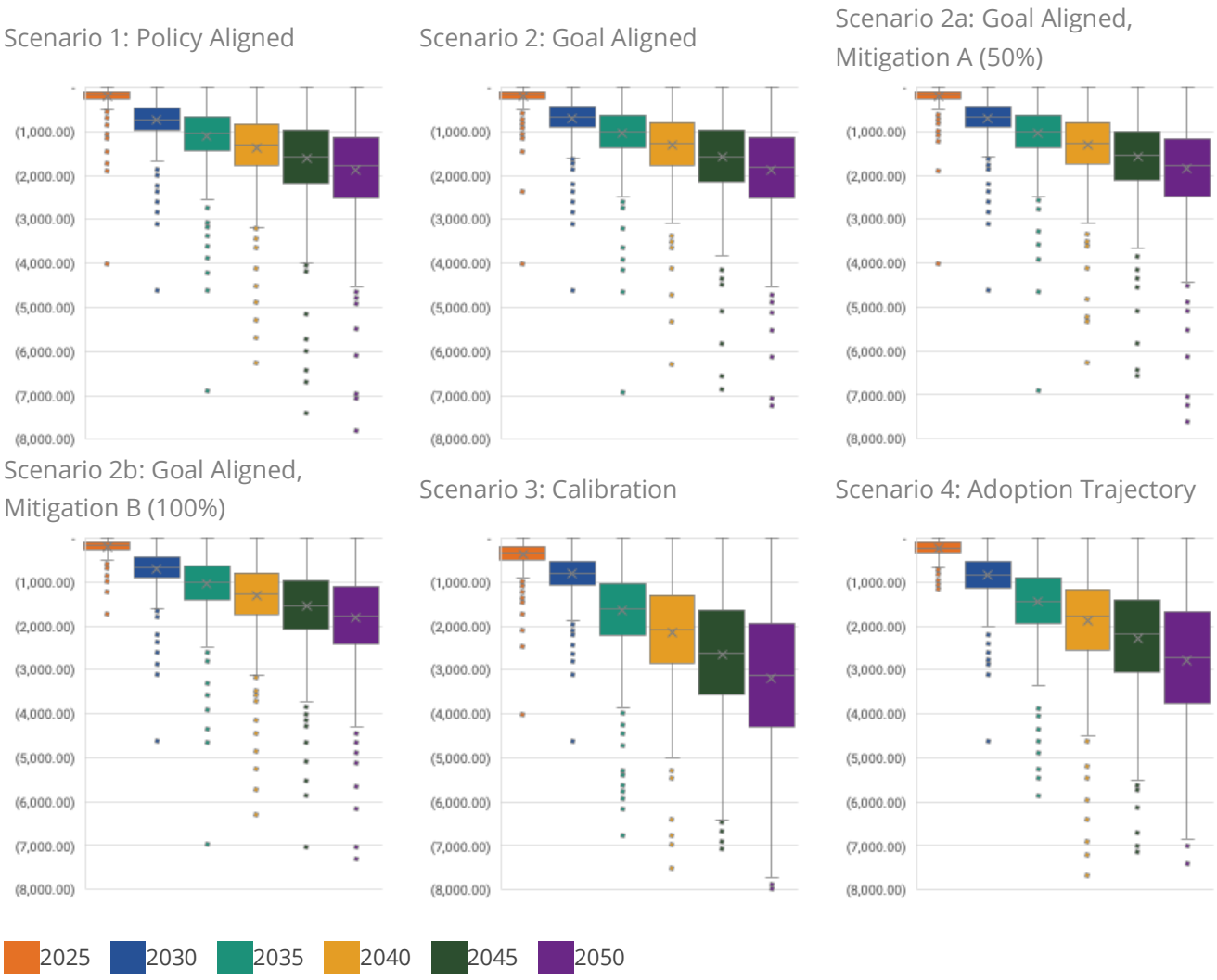
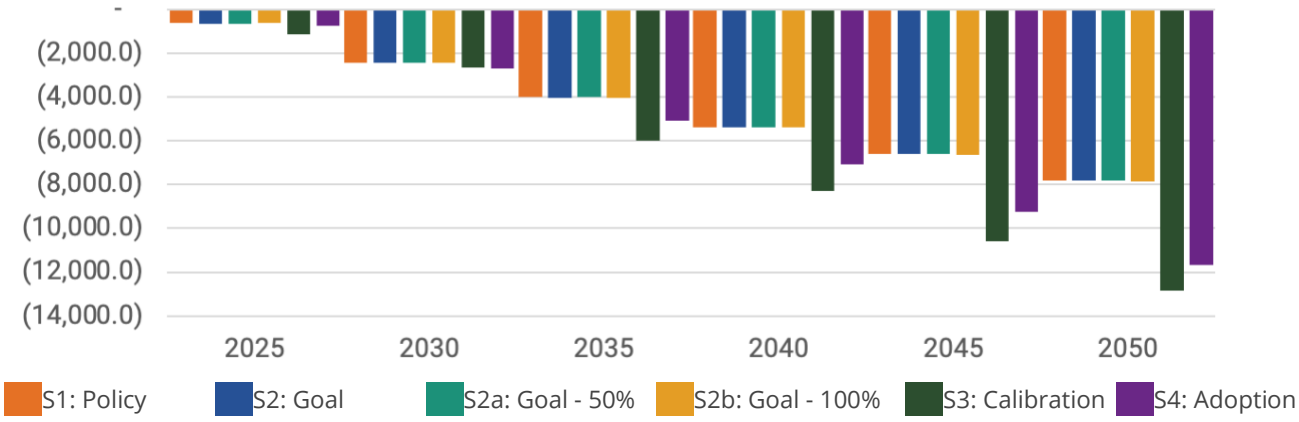


Figure H-12 shows the cumulative energy savings from EE for selected years by scenario.

Figure H-12: Cumulative energy savings (kW) from EE by year and scenario: 2025-2050 (Source: Kevala)



The following are key findings from Kevala's analysis of the EE results:

- The actual EE measures can impact service point behaviors in many ways, in part because the technologies are impacted by customer behavior choices. As a result, the approach focuses on savings based on historical performance of EE activities.
- The adoption of EE measures can also vary depending on the age of legacy technologies at the service point. Limited data on actual adoption trends within the PSCo's service territory was available, so Kevala used stochastic selection of service points.
- EE continues to be an effective mitigation approach to managing both peaks and energy use. Additional efficiency technologies that address DER efficiency could further mitigate the impact of some DERs, particularly those related to space heating.

Appendix I. Demand Response Modeling Methodology and Additional Results

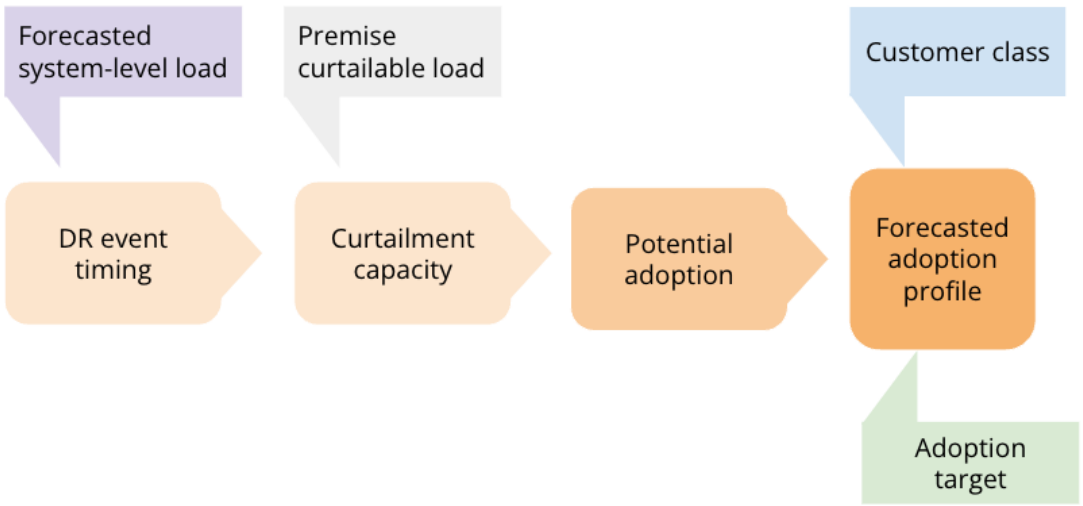
I.1 Approach

Demand response (DR) involves the use of programs providing customers with incentives to adjust their energy use for a specified period when requested by a utility. Typically, these programs involve notifying participating customers that a DR event is being called or enacted. The participating customer enrolls in the program (prior to a DR event) with the understanding they would be either compensated for reducing their energy use to a certain level for each event or potentially penalized via higher-than-normal rates for the event hours (critical peak pricing).

For DR modeling, Kevala's approach required defining the size, behavior, and adoption of the energy reduction during DR events. Unlike other demand modifiers, DR represents an agreement between a customer and a utility that can be canceled or renegotiated over time. A business may not want to participate in DR events if its needs change, or a utility may need to change its portfolio of DR adopters if the system characteristics change (e.g., the system peak may be shifted due to EVSE adoption). To capture this fluidity, rather than model adoption of this form of DR as a permanent change to a premise, Kevala reruns DR eligibility, adoption, and sizing for all premises each year.

Figure I-1 shows Kevala's modeling approach to determine premise-level DR demand modifier estimates.

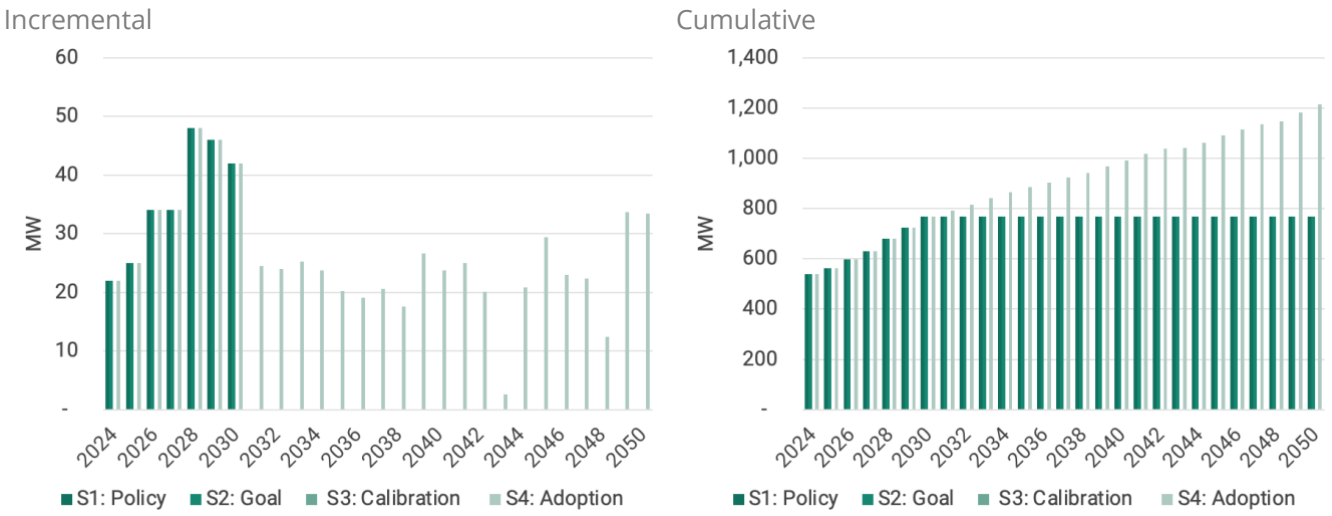
Figure I-1: Flow diagram of DR modeling (Source: Kevala)



DR events were split between residential and non-residential (C&I customers). Residential customers accounted for 55% of total megawatts (MW) reduced through events, which occurred

only on hot summer days. Residential premises participated in 20 DR events per year lasting 3 hours each. Non-residential DR events accounted for the remaining 45% of reduced MW and could occur throughout the year. Non-residential customers participated in 10 events per year, each with a 4-hour duration. Figure I-2 shows the DR targets used for this study. Note there are no targets for the Calibrated scenario and the targets for the Policy and Goal Aligned scenarios were the same. Further, the targets for the Policy and Goal Aligned scenarios drop to zero after 2030 while the targets for Adoption Trajectory continue through the end of the study period.

Figure I-2: Incremental and cumulative DR targets (MW) by scenario: 2024-2050 (Sources: PSCo, Kevala)



I.1.1 Sizing

For all DR events, Kevala assumed 100% of the target megawatts were curtailed and all customers adopting DR that year participated in each DR event. Up to 50% of a premise's load was eligible to be curtailed during a DR event.[54] This load was curtailed, or reduced, equally across all DR event hours.

I.1.2 Behavior

DR targets were specified as a certain number of events at a set level of system-level megawatt curtailment over a certain duration (in hours). All scenarios except Scenario 3, the Calibration scenario, included DR events.

To determine the timing of these events each year, Kevala first identified days with the largest system-level peaks (one day per DR event). For each day, an event period was selected that

[54] Curtailable load includes base load, energy efficiency (EE), battery energy storage systems (BESS), heat pump water heating (HPWH), heat pump heating, ventilation, and air conditioning (HP HVAC), personal electric vehicle supply equipment (EVSE), and fleet EVSE.

contained the daily system peak to minimize that peak. If multiple event periods met these criteria, Kevala chose the period with the highest total system-level demand.

I.1.3 Adoption

Kevala based adoption propensity scores on curtailment capacity. A premise must have a minimum amount of curtailable load to be considered eligible for an event. Those premises with more capacity to reduce during DR events in a given year received a higher propensity score and were more likely to be selected to participate in DR that year.

The following are the key assumptions associated with DR modeling:

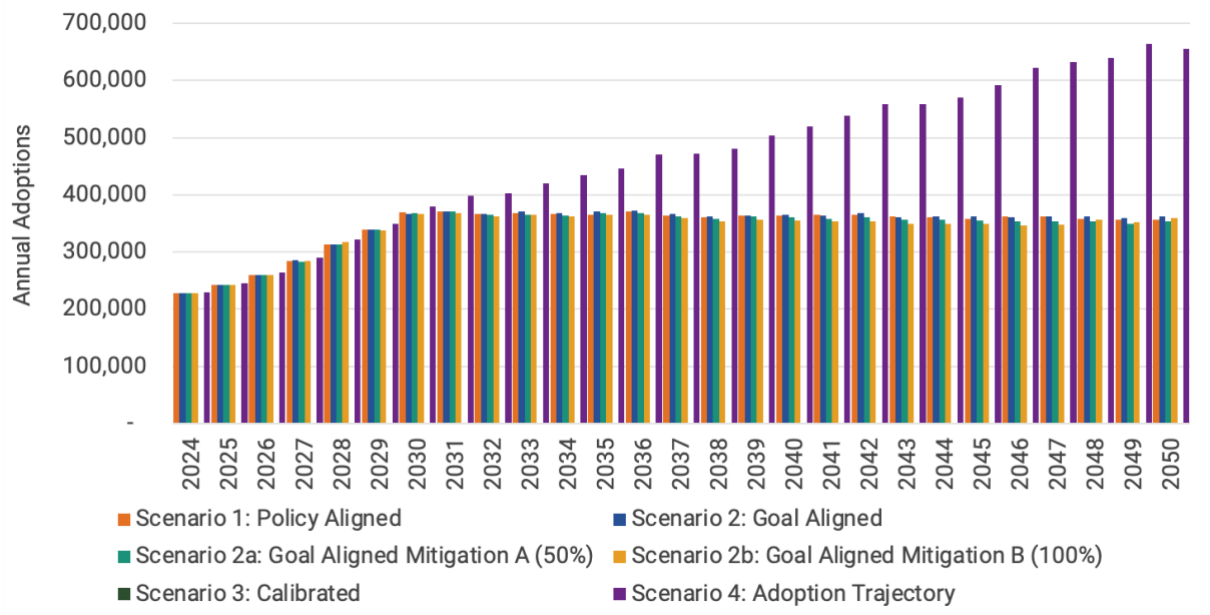
- All customers participate equally in all DR events.
- For residential, the events were only applied to summer months, potentially minimizing the impact of DR programs that target peak winter days. This assumption was based on PSCo's current DR programs that target hot summer days.
- Customers with higher energy use are more likely to participate in a DR program than those with low levels of energy use, thus the number of adopters may be understated.
- DR programs are used throughout the study period despite the targets dropping off for Policy and Goal Aligned scenarios after 2030.
- Customer enrollment choices are made each year with no dependencies on whether the customer previously enrolled.
- DR events are triggered by system-level peaks versus feeder-specific peaks.

I.2 Analysis and Results

The results of the DR modeling are described in detail below. Figure I-3 shows the incremental and cumulative DR adoptions by scenario and year. These adoptions track with the targets shown in Figure I-2. Figure I-4 shows the distribution of adoptions on feeders by scenario and year in a series of box and whisker charts (see Figure F-6 and the accompanying text for more detail on this type of chart). The x-axis shows the study year while the y-axis shows the range of the number of DR adoptions. As these charts show, the adoption levels of DR for Policy and Goal aligned scenarios increases through 2030 then level off, aligned with the targets.

Figure I-3: Incremental and cumulative DR adoptions by scenario and year: 2024-2050 (Source: Kevala)

Incremental



Cumulative

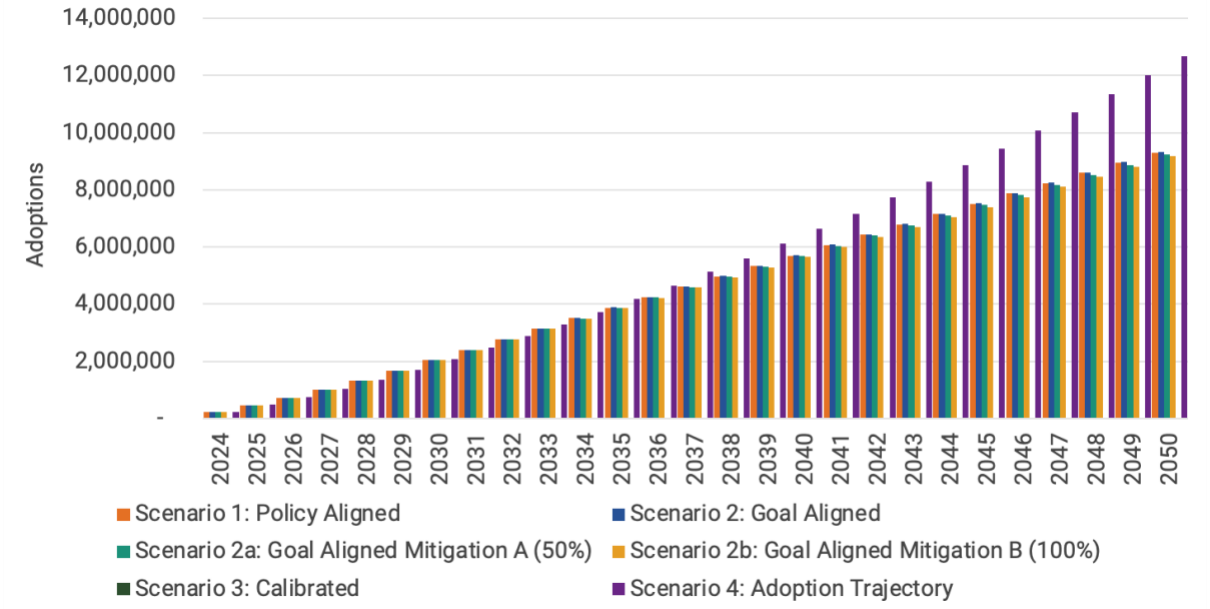


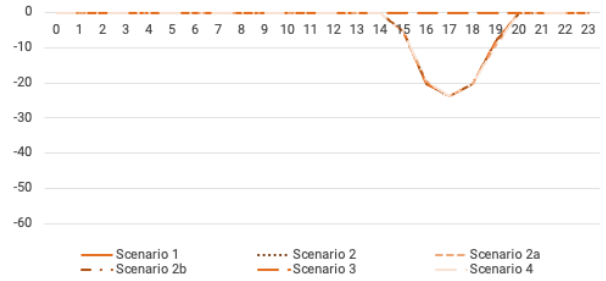
Figure I-4: Distribution of DR adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)



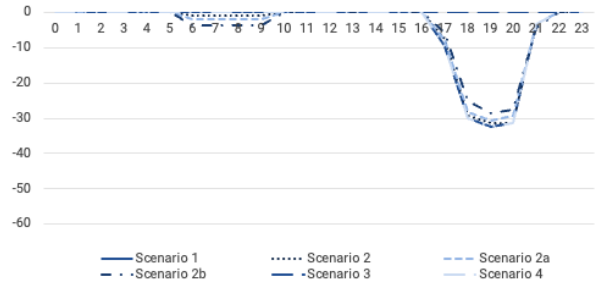
The DR average load shapes for all the scenarios are shown in Figure I-5. These charts show the expected average generation behavior from DR-participating premises. The behavior shapes reflect the assumption that the DR program is mostly available for residential customers during hot summer days as the DR response is mostly between 1700 and 2200 hours. In later years, the impact of C&I DR, which is year-round, reflects peak hours between 0600 and 1000 hours. Note these charts are showing average DR behavior at the premise and do not include losses.

Figure I-5: DR average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala)

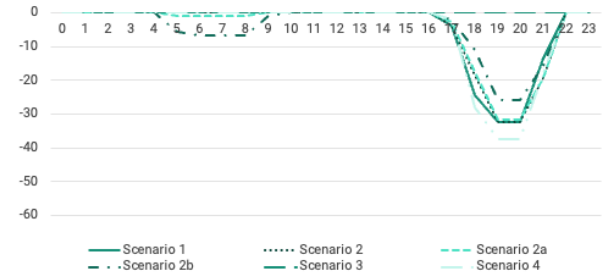
2025



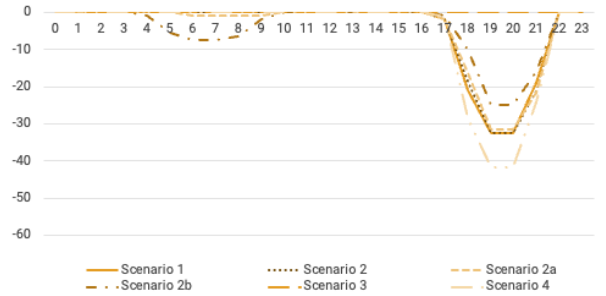
2030



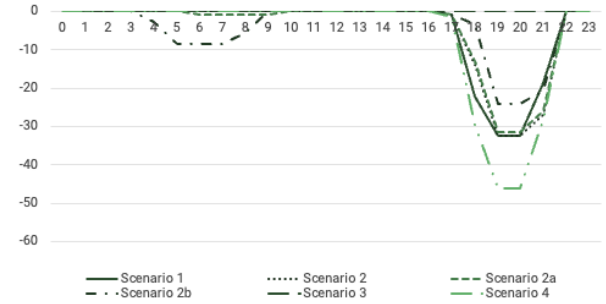
2035



2040



2045



2050

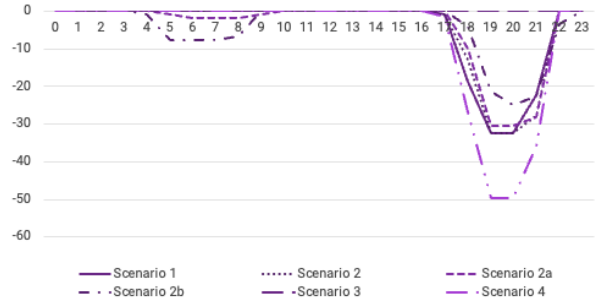


Figure I-6 shows the adoptions geographically. As these diagrams show, the adoptions are not concentrated in any geographic area and increase equally over time. This is the result of assuming DR is based on premise loads rather than customer characteristics for adopting a DER. Note the Calibration scenario had no targets and thus no adoptions.

Figure I-6: DR adoption across PSCo's service territory, Scenario 2 (Policy Aligned): 2025-2045 (Source: Kevala)

Scenario 2: Policy Aligned

2025 2035 2045

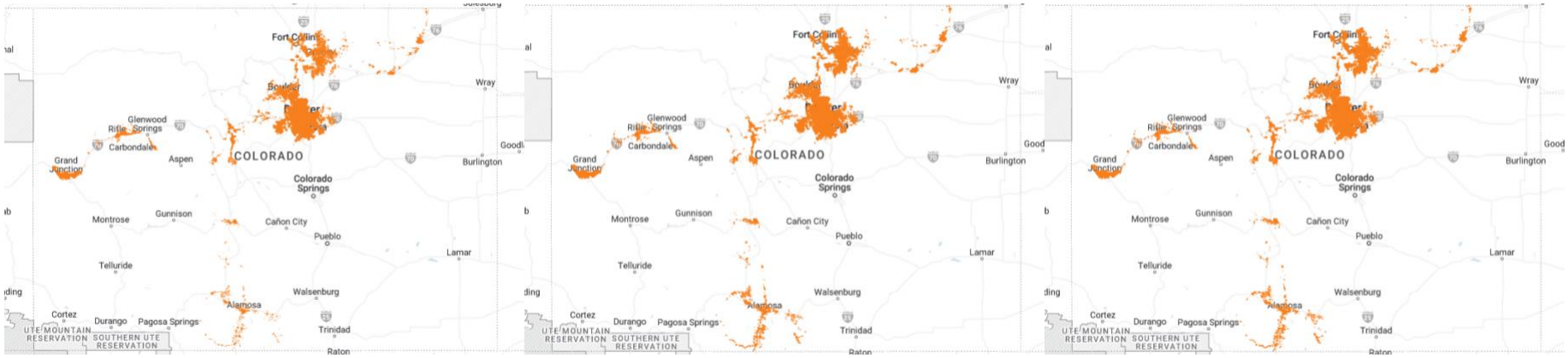


Figure I-7 and Figure I-8 are box and whisker charts showing the distribution of the contribution of DR to the feeder coincident peak and noncoincident peaks, respectively. The x-axis shows the study year while the y-axis shows the range of capacity contribution (kW) of the DER to system peak load. Because the DR programs are focused on curtailing load during peak hours, the impact on system load is noticeable in most scenarios. Interestingly, the DR program is not impacting the system peak day feeder loads in certain years primarily because the net load system peak is occurring in the winter and thus the benefits from residential DR are not present.

The implications on feeder peaks are also interesting. First, there are far more outliers and a very wide distribution, driven by the bias of DR adopters linked to size of customer. That is, the expected savings on a feeder are driven in part by the size of the load of the premises participating in the DR event. Second, the variation among scenarios is very apparent, with the DR events having minor impacts in the Goal Aligned and Goal Aligned - Mitigation B (100% mitigated) scenarios, where the peak is being shifted from the DR period of 1700 to 2200 hours. This is also seen in the Goal Aligned - Mitigation A (50% mitigated) scenario but to a lesser extent.

Figure I-7: Distribution of DR at the system peak (kW) by year and scenario, 2025-2050 (Source: Kevala)

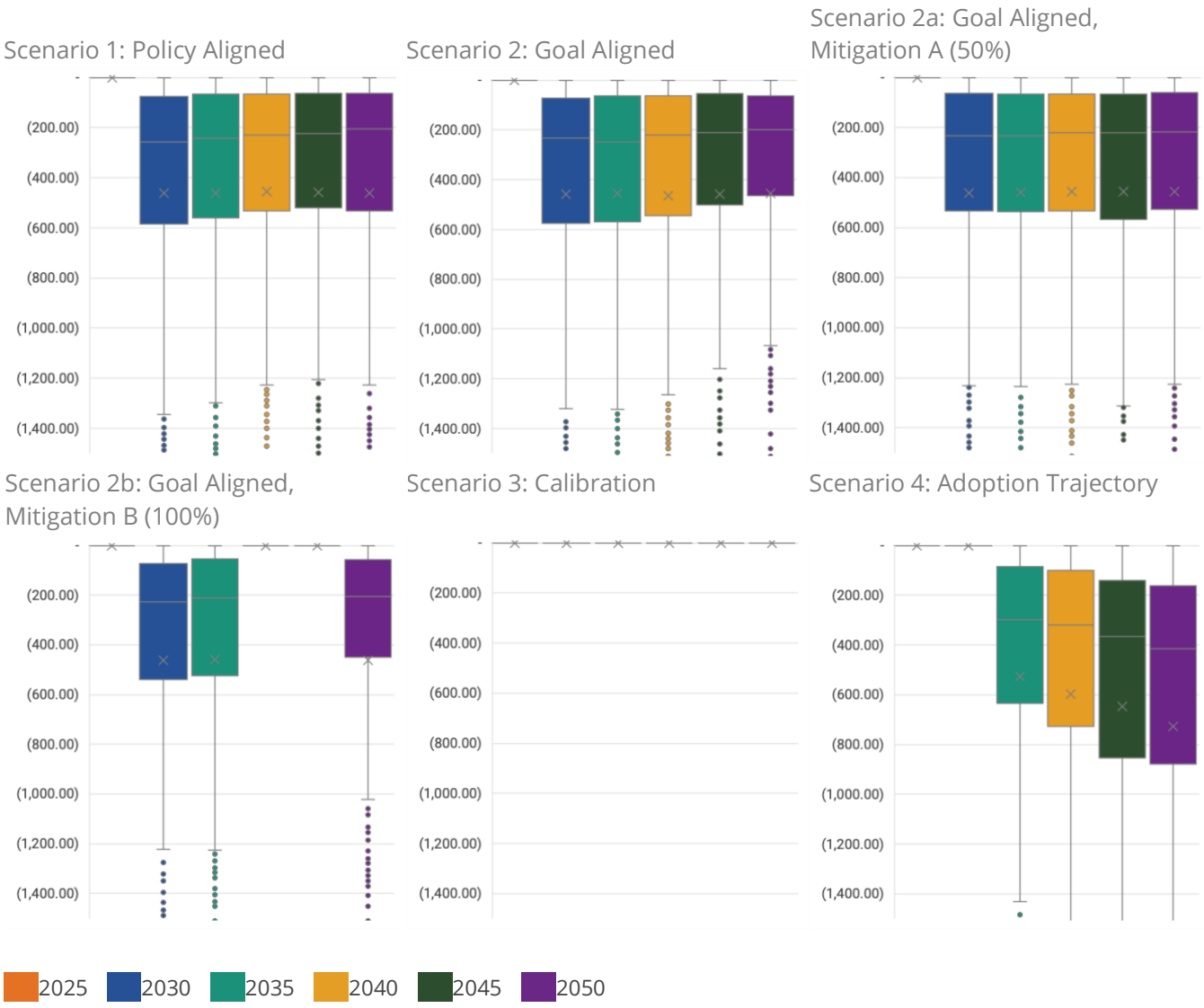


Figure I-8: Distribution of DR at the feeder peak (kW) by year and scenario, 2025-2050 (Source: Kevala)

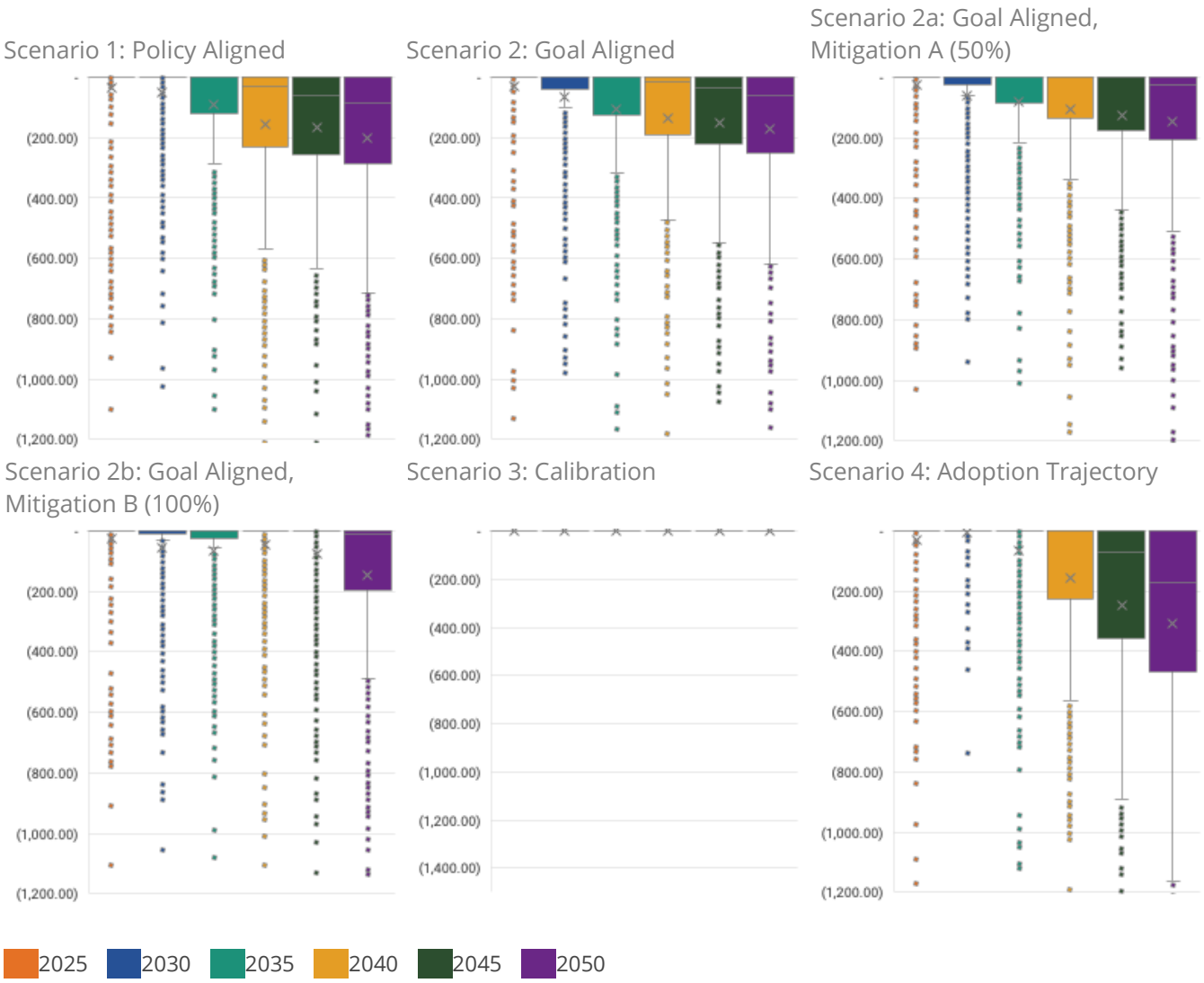
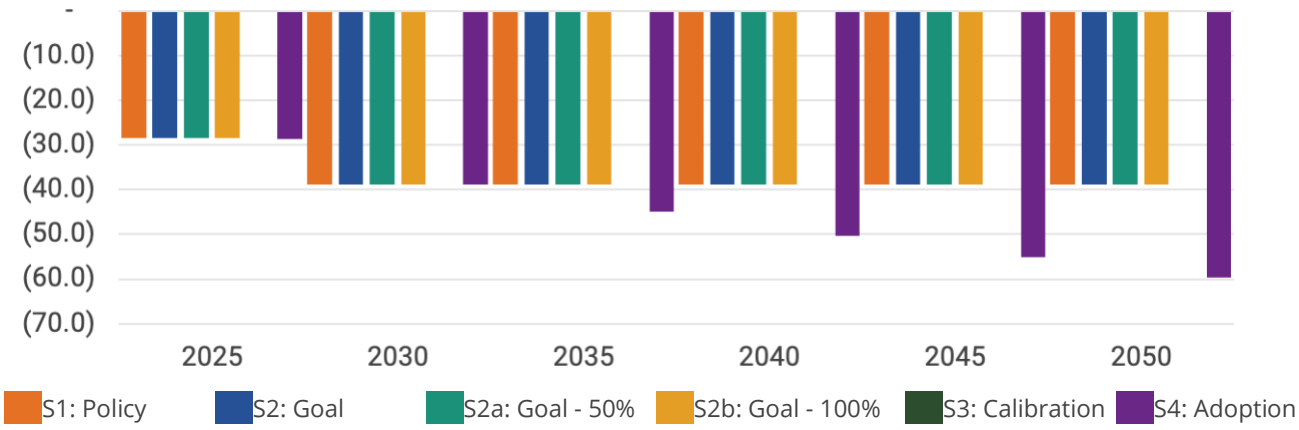


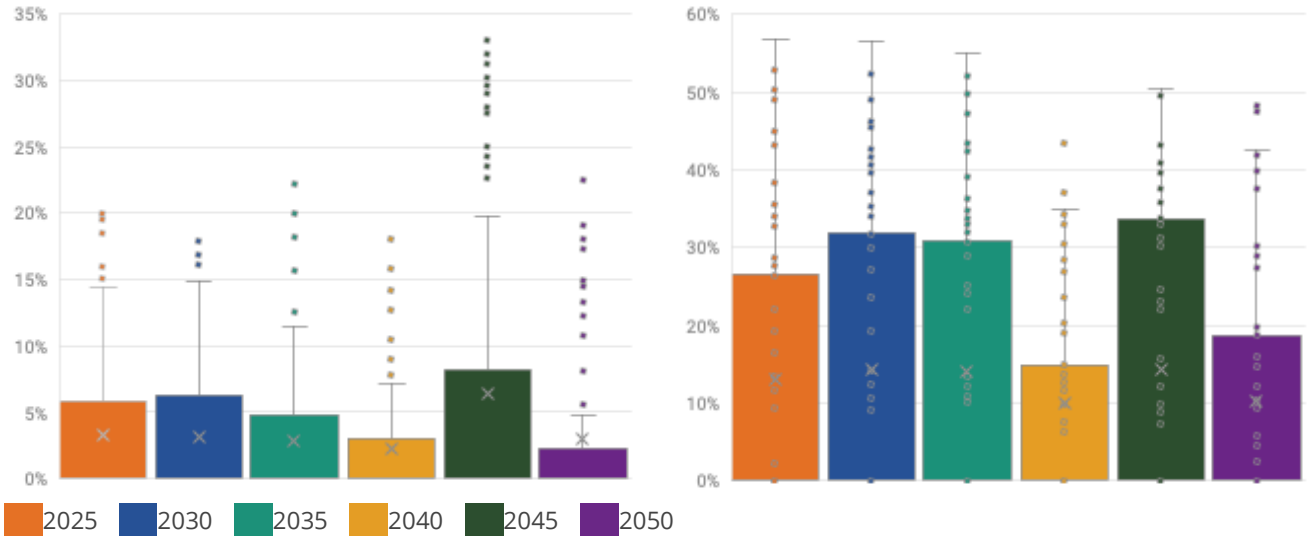
Figure I-9 shows the cumulative energy reductions from DR for selected years by scenario.

Figure I-9: Cumulative energy reductions (GWh) from DR by year and scenario: 2025-2050 (Source: Kevala)



Lastly, Kevala examined the timing of system versus feeder peaks to further explain the impact of DR on feeder peaks. Figure I-10 shows that in all scenarios, less than 35% of feeders peak in the same hour as the system peak. This improves when looking at the percentage of times the feeder peaks on the same day as the system peak. This is because the hours of feeder peak could be within range of the system peak but not the exact hour. Therefore, the impact of DR could be greater with wider DR event bands (assumed to be 4 hours in this study).

Figure I-10: Percentage of feeders peaking coincidently with system peak by scenario (Source: Kevala)



The following are key findings from Kevala's analysis of the DR results:

- DR reduces peaks on feeders, helping to mitigate distribution needs on system and feeder peak days.

- The frequency of feeders peaking at the same time as the system is low at approximately 3% across most scenarios (6% for the Calibration scenario) and could limit the mitigation options for DR if system-level signals are used exclusively.
- There is some evidence that the peaks on feeders are occurring at greater frequency (approximately 14% for the Policy Aligned, Goal Aligned, and Goal Aligned - Mitigation A (50%) scenarios and 10% for the Goal Aligned - Mitigation B (100%) and Adoption Trajectory scenarios), so DR programs may be more effective with longer duration peak events.

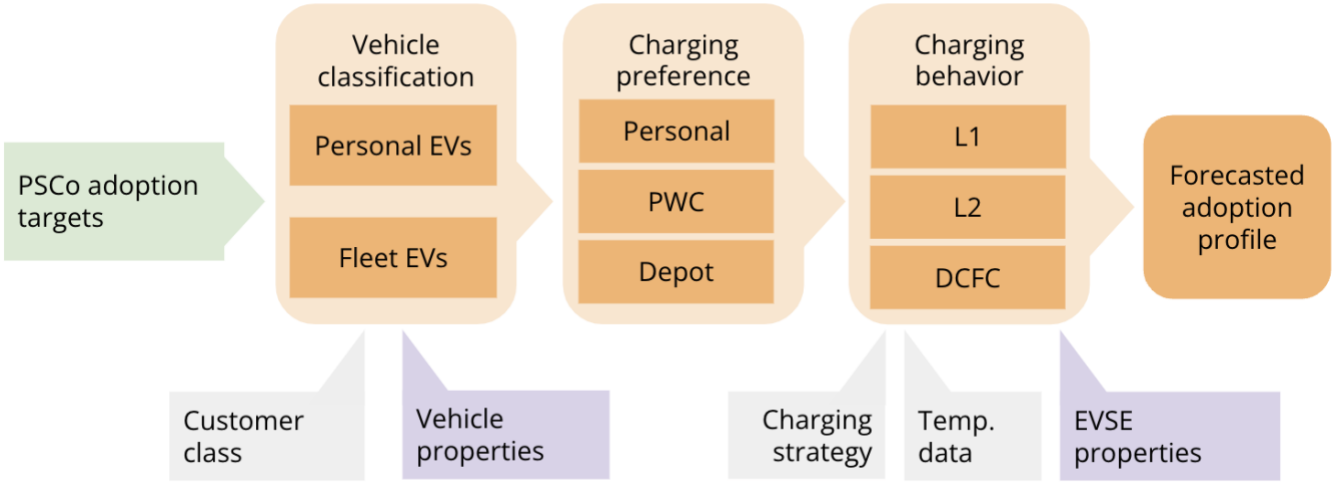
Appendix J. EV and EVSE Modeling Methodology and Additional Results

J.1 Approach

Kevala's EV and EVSE methodology consists of two adoption pipelines. One pipeline models the adoption of EVs while the other models the adoption of the required EVSE. EV adoption informs a premise's EVSE adoption, and EVSE demand is simulated according to premise-level EVSE characteristics combined with EV properties and driving patterns.

Figure J-1 summarizes the high-level methodology that Kevala employed to model the energy impact associated with varying levels of EV adoption.

Figure J-1: Overview of EV/EVSE modeling approach (Source: Kevala)



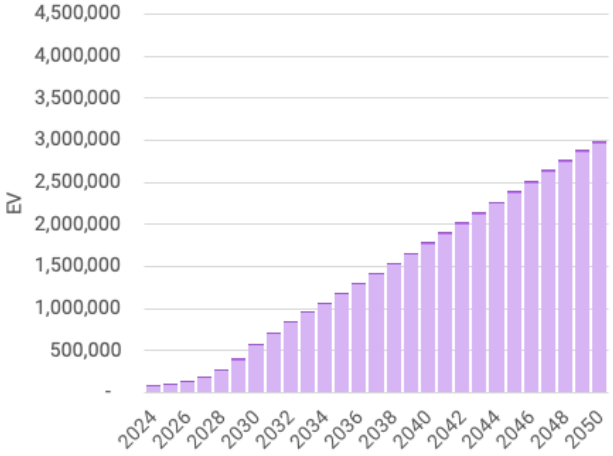
J.2 EV Adoption Pipeline

J.2.1 EV Target Setting

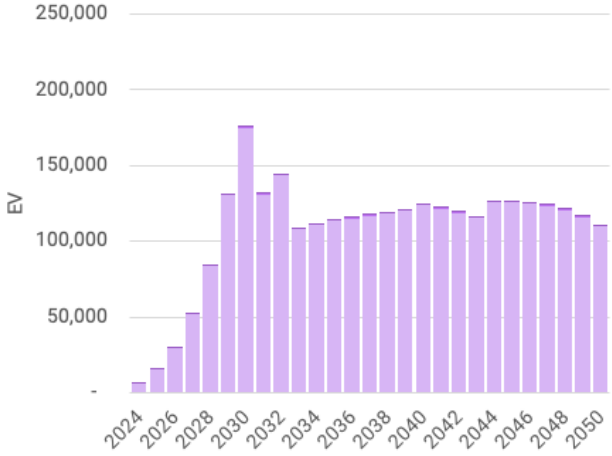
For all EV types, the number of EVs were based on targets provided by PSCo for light-duty vehicles (LDVs), medium-duty vehicles (MDVs), and heavy-duty vehicles (HDVs) (see Figure J-2).

Figure J-2: EV targets (vehicles) by duty, year, and scenario (Sources: PSCo, Kevala)

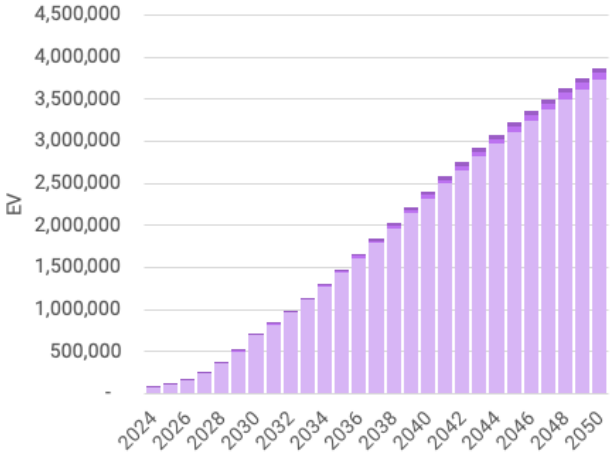
Scenario 1: Policy Aligned - Cumulative



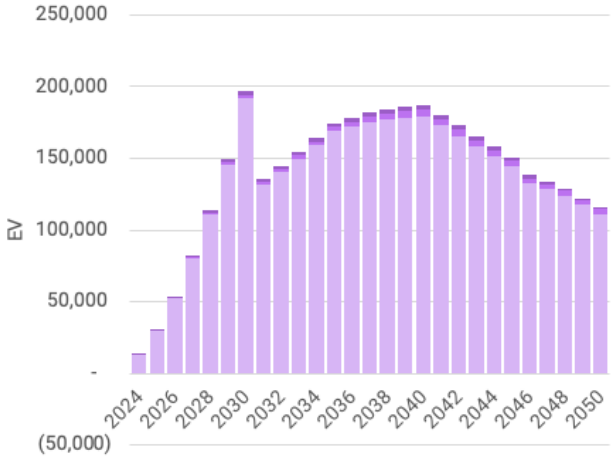
Scenario 1: Policy Aligned - Incremental



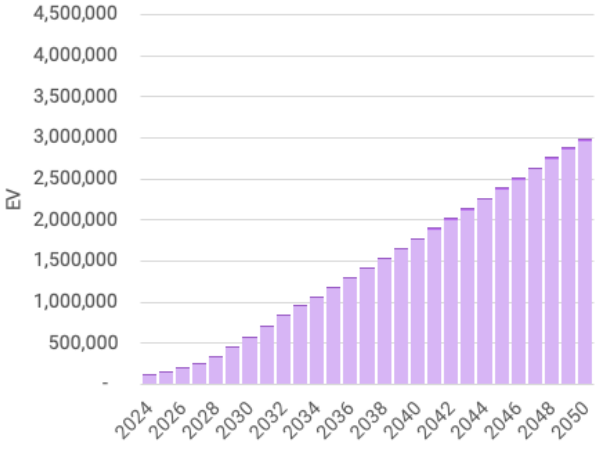
Scenario 2: Goal Aligned - Cumulative



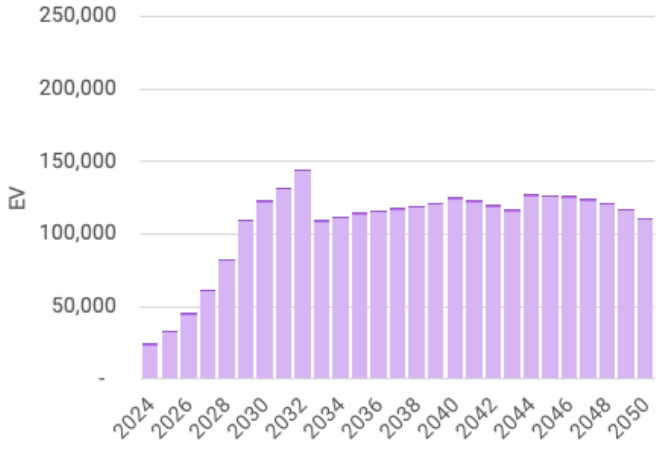
Scenario 2: Goal Aligned - Incremental



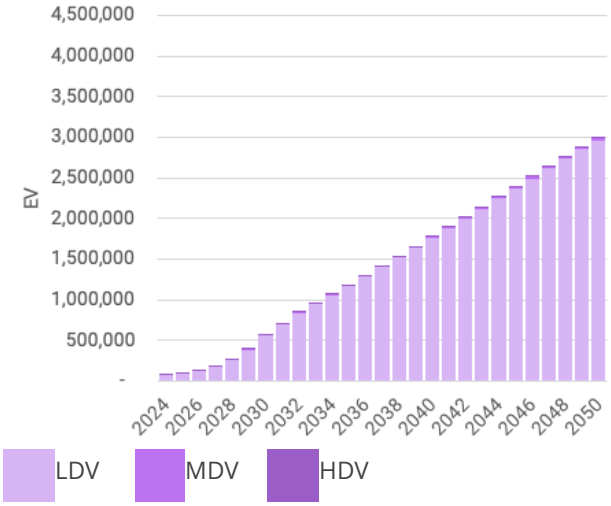
Scenario 3: Calibrated - Cumulative



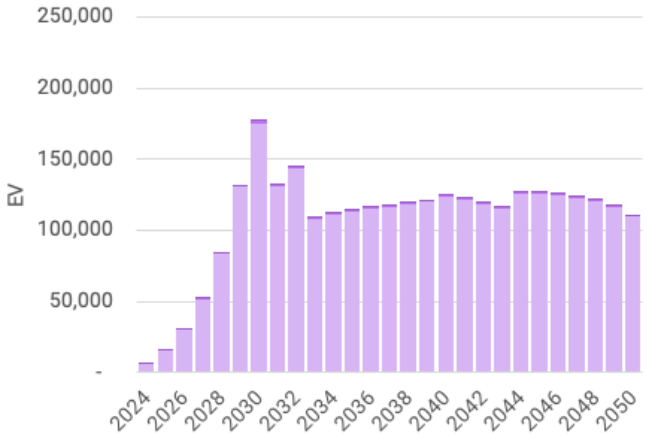
Scenario 3: Calibrated - Incremental



Scenario 4: Adoption Trajectory - Cumulative

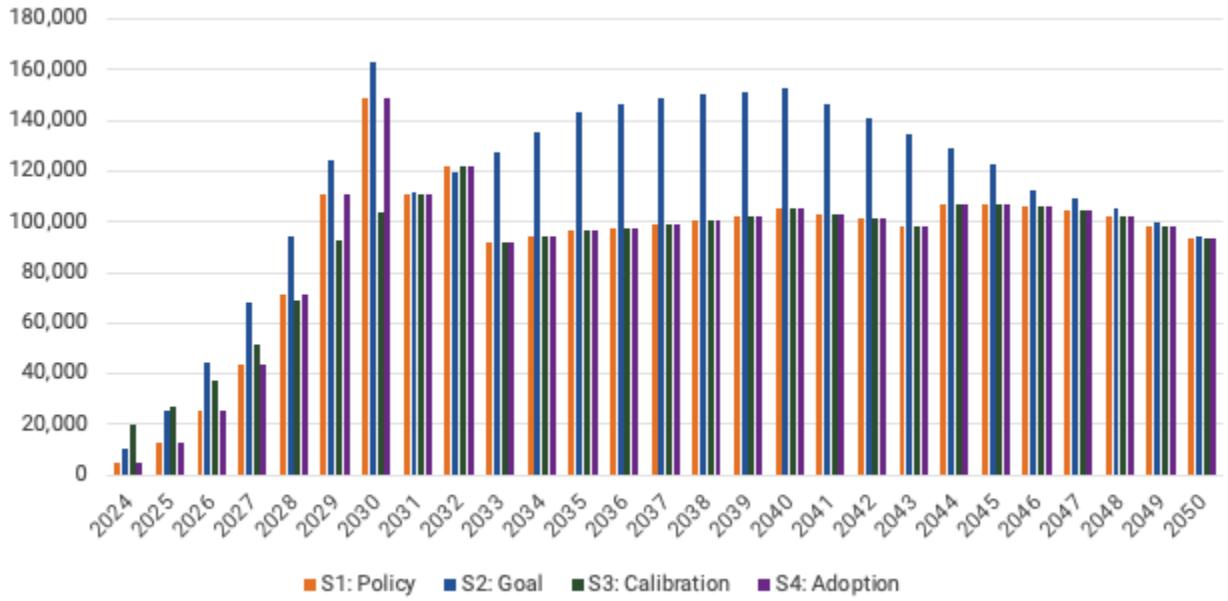


Scenario 4: Adoption Trajectory - Incremental



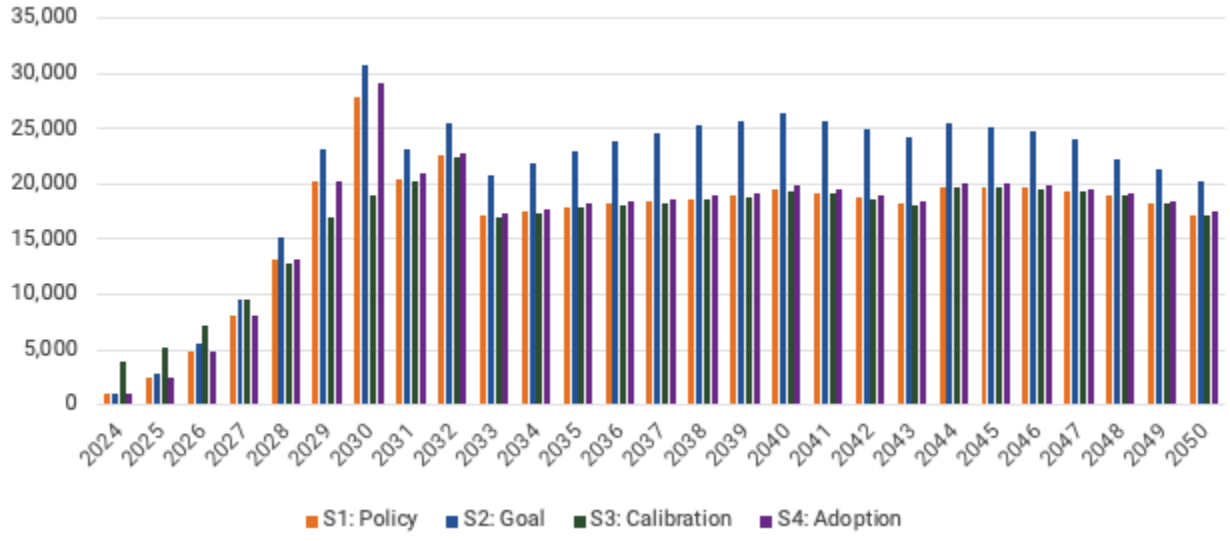
Of these targets, Kevala assumed that personal light duty vehicles were 85% of the LDV targets and 0% of the MDV and HDV targets.[55] Fleets made up the remaining 15% of LDV and 100% of MDV and HDV targets.

Figure J-3: Personal EV targets (vehicles) by scenario, 2024-2050 (Sources: PSCo, Kevala)



[55] This ratio was based on a variety of sources, including the California Energy Commission's Integrated Energy Policy Reports, California Air Resources Board studies, and Kevala's subject matter experts.

Figure J-4: Fleet targets (vehicles) by scenario, 2024-2050 (Sources: PSCo, Kevala)



J.2.2 EV Sizing and Adoption

Based on the EV targets, the sizing methodology selected the duty, powertrain, and vehicle class according to the known distribution of EVs in the region.[56] The macro-categories in the Kevala vehicle classification system are based on the California Energy Commission (CEC) Assembly Bill 2127 report.[57]

Personal EVs

Personal light duty electric vehicles (personal EVs) were assumed to be for residential customers, so only residential premises were eligible for adoption. For every residential customer, a sizing model defined the type of personal EV that the customer would be allocated in case the customer adopted during the forecast period. Per guidance from PSCo, Kevala assumed a varied ratio of battery electric vehicles (BEVs) to plug-in hybrid electric vehicles (PHEVs) depending on the scenario. The probabilities of being sized for one of the different vehicle types were equal. A premise could adopt one, two, or three personal EV (based on *The Geography of Transport Systems*) and was capped at adopting three Personal EVs.[58]

All premises sized for personal EVs were stochastically selected for adoption with equal weighting until the targeted number of personal EVs were adopted in each year. The sizing and adoption targets reflected the known proportion of vehicle types from the Experian VIO data.

[56] Known distribution of EVs in the region is based on vehicles in operation (VIO) data from Experian.
[57] California Energy Commission, Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment, February 2024 https://efiling.energy.ca.gov/GetDocument.aspx?tn=254869
[58] Rodrigue, Jean-Paul, "Chapter 8 – Urban Transportation," The Geography of Transport Systems, Sixth Edition, 2024, https://transportgeography.org/contents/chapter8/

Fleet EVs

A premise's eligibility to host a fleet EVSE was constrained to only non-residential premises because it is unlikely for a fleet charging depot to be located on a residential property. Sizing and adoption consisted of defining the type of fleet vehicle a premise would adopt as well as the EV counts in such a fleet. LDV fleet vehicles consisted only of the Small Car BEV and Small Car PHEV vehicle types. The MDV and HDV classification consisted of a slightly modified version of the vehicle used by the CEC in the AB 2127 report. In addition, MDV and HDV only considered BEVs, not PHEVs.

Kevala used a stochastic approach to select the type of vehicle for the fleet and the number of EVs, with the latter constrained between 3 and 20 with a uniform distribution.

To predict which premises were most likely to adopt a fleet, the adoption model assigned each premise an adoption propensity score between 0 and 1. This adoption score equaled the weighted total of the normalized parcel area and normalized building footprint, where a larger parcel area and large building footprint correspond to a higher adoption score. Note that for agricultural parcels, a different upper bound was considered for normalizing parcel area to avoid bias as agricultural land is often extensive.

J.3 EVSE Adoption Pipeline

Kevala's EVSE forecasting methodology produces results for three different charging types:

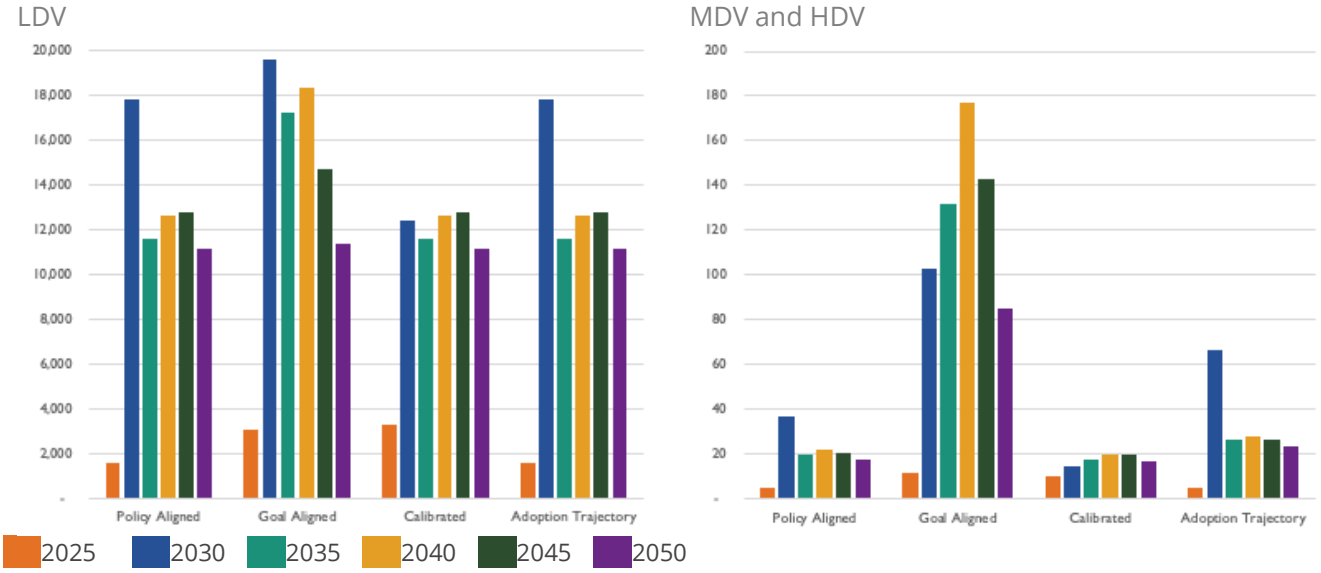
- Personal EV home charging: EVSE equipment installed at the premise of a residential customer, which is used to service the customer's personal EV.
- Fleet depot charging: EVSE equipment installed at a premise to service a fleet of LDVs, MDVs, or HDVs at its main location (e.g., a depot). Fleets include buses, delivery vehicles, and rental cars.
- Public, workplace, and corridor (PWC) charging: EVSE equipment installed at a premise to service LDV, MDV, and HDV charging needs at a place of business or a public charging facility (akin to a traditional gas station). This category also includes corridor charging facilities that service LDVs, MDVs, and HDVs and are typically located along major transportation corridors such as interstate highways or intrastate roadways.

J.3.1 EVSE Target Setting

In the case of personal EV and fleet EV targets, Kevala did not consider service territory targets for their EVSE infrastructure because the latter was directly informed by the EV adoption model. In other words, any personal EV adopter would also adopt EVSE at their home; similarly, any fleet adopter would adopt corresponding EVSE at their depot. However, for PWC EVSE, a service territory-level target was created, dependent on the targets of total EVs from the personal EVs and

fleet EVs. Kevala applied EV-to-EVSE ratios from Kevala's proprietary database. These targets are provided in Figure J-5 by scenario and year.

Figure J-5: Annual PWC EVSE targets (plug counts) by forecast year (Source: Kevala)



J.3.2 EVSE Sizing and Adoption

The sizing step required identifying the type of EVSE equipment needed to meet the load of the EVs at the premise. These techniques vary by the type of charging.

Personal EVSE – Home Charging

For residential personal EV adopters, Kevala followed these assumptions:

- A premise either will get either a Level 1 (L1) or Level 2 (L2) EVSE; a premise may not have both L1 and L2 EVSE.
- If a premise is given L1 EVSE, there will be a 1:1 ratio between EVs and EVSE (e.g., 3 EVs, 3 L1 EVSE).
- If a premise is given L2 EVSE, the number of EVSE depends on the number of EVs as follows:
    - 1 EV: 1 L2 EVSE
    - 2 EVs: 2 L2 EVSE
    - 3 EVs: 2 L2 EVSE

DC fast chargers (DCFC) were excluded from the choice of EVSE equipment for personal EV charging. The percentage of L1 versus L2 chargers was based on an EV trends study.[59] For this study, 29% of personal EVSE was L1 and rated at 1.9 kW while 71% was L2 and rated at 7.2 kW.

Fleet EVSE – Depot Charging

In the case of fleet vehicles, the following EV count to EVSE plug ratios and plug capacity were considered:

- For LD EV fleets:
  - 1:1 EV:EVSE ratio
  - L2 (19 kW) EVSE
- For MD/HD EV fleets:
  - 2:1 EV:EVSE ratio (rounding up, if necessary)
  - DCFC (50 kW) EVSE

These capacities and plug counts were defined based on Kevala's subject matter expertise.

PWC

Only non-residential premises were eligible for PWC EVSE. Kevala applied a stochastic process and a uniform distribution of weights to determine which of the three PWC EVSE types would be adopted for each premise. For public and workplace EVSE, adoption scoring considered a premise's size relative to other premises in its county and if it was near commercial premises. For corridor EVSE, the adoption score considered distance to the nearest corridor. For PWC EVSE that served MDVs and HDVs, adoptions were favored at premises that were a known truck stop.

Kevala selected an EVSE plug quantity based on clusters derived from Kevala's proprietary database. These are:

- DCFC plug clusters: 2, 3-5, 6-12
- L2 plug clusters: 2, 3-4, 5-10, 11-25, 26-50

A stochastic approach was used to select the cluster sizes that match distributions of the mix of sizes from Kevala's proprietary database. For example, if a premise was selected as public, L2, and LD, the number of L2 plugs would be one of the values in the L2 plug clusters. If the selected value was a range (e.g., 11-25), the final EVSE count was uniformly sampled from this range.

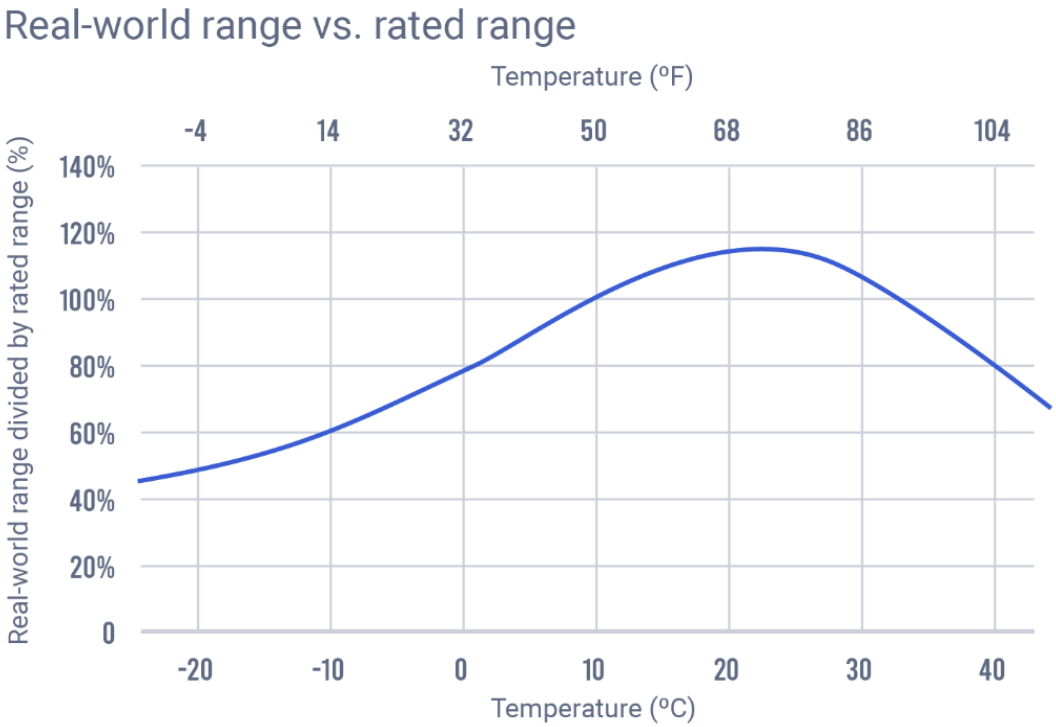
J.3.3 Behavior

The last step in the EVSE charging forecast was to determine the hourly charging behavior for each EV and where they would use EVSE. Each EV was given its own vehicle properties, which included

[59] Opinion Dynamics, PG&E Electric Vehicle Automated Demand Response Study Report, February 2022, https://opiniondynamics.com/wp-content/uploads/2022/03/PGE-EV-ADR-Study-Report-3-16.pdf

battery capacity, range, efficiency (in kWh per mile traveled), and projected technological improvements over time.[60] Kevala accounted for the impact of temperature on vehicle efficiencies based on a Geotab study (see Figure J-6).[61] Specifically, vehicles performed worse during periods of very hot or very cold weather.

Figure J-6: Temperature range curve (Source: Geotab)



Each vehicle was also given its own driving properties, which included arrival and departure times, daily vehicle miles traveled (VMT), and frequency of active driving days during the week (e.g., Monday, Tuesday). These driving patterns depended on vehicles being personal use versus fleet and if the charging events happened at a home, fleet depot, or PWC location. Note that for fleets, additional driving pattern diversity was modeled depending on the vehicle class.

Each day of the forecast, vehicles had different variances applied to their driving schedule (arrival/departure times) and VMT. Vehicles charged according to different charging strategies depending on the scenario:

- **Unmanaged:** Vehicles charged upon arrival at their depot to full power (100% state of charge).

[60] EPRI and Natural Resources Defense Council (NRDC), Valuing Improvements in Electric Vehicle Efficiency, April 2024, https://www.epri.com/research/products/000000003002030215
[61] Argue, Charlotte, "To what degree does temperature impact EV range?" Geotab, November 30, 2023, https://www.geotab.com/blog/ev-range/

- **Managed-load:** Vehicles charged to minimize the local (premise-specific) peak due to charging and asset net load. This strategy spread charging across the full charging window and avoided charging during periods of high base load.

Further, the model allowed for up to two charge events per EV per active driving day depending on the vehicle type (e.g., a secondary lunch charging event was modeled for school buses). Specifically, if a premise's active driving days were Monday, Wednesday, and Friday, charging would only occur on those three days. For personal and fleet vehicles, Kevala assumed 20% of charging took place at PWC EVSE.[62] Active days for PWC charging were chosen for each EV stochastically.

For PWC, EVSE behavior was influenced by the number of expected charge events per day. Kevala assumed the number of charge events per day for each PWC EVSE as follows:

- Public LDVs: 7
- Public MDVs or HDVs: 2
- Workplace LDVs: 6
- Corridor LDVs: 10
- Corridor MDVs or HDVs: 9

J.4 Analysis and Results

The following sections provide the results, broken out between personal, fleet, and PWC EVSE.

J.4.1 Personal EVSE

Figure J-7 shows incremental (i.e., the number each year) and cumulative personal EVSE adoptions by scenario and year. These adoptions track with the targets shown in Figure J-2.

[62] California Energy Commission, Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment, February 2024 https://efiling.energy.ca.gov/GetDocument.aspx?tn=254869; NREL, The 2030 National Charging Network: Estimating U.S. Light-Duty Demand for Electric Vehicle Charging Infrastructure, June 2023, https://www.nrel.gov/docs/fy23osti/85654.pdf

Figure J-7: Incremental and cumulative personal EVSE adoptions by scenario and year: 2024-2050 (Source: Kevala)

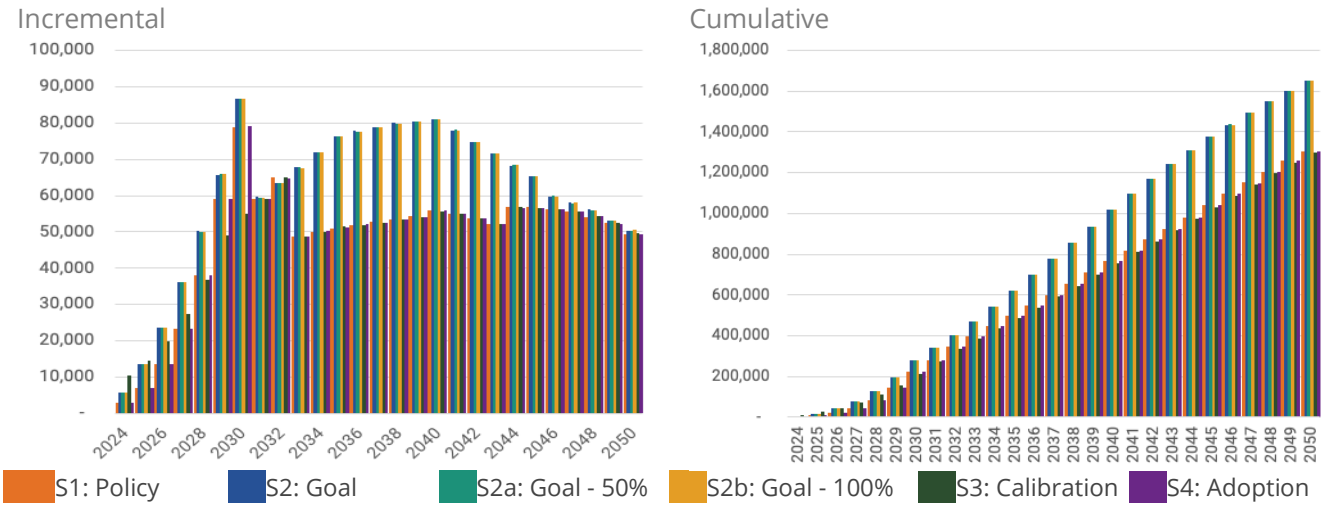


Figure J-8 shows the distribution of adoptions on feeders by scenario and year in a series of box and whisker charts (see Figure F-6 and the accompanying text for more detail on this type of chart). The x-axis shows the study year while the y-axis shows the range of the number of personal EVSE adoptions.

Figure J-8: Distribution of personal EVSE adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)



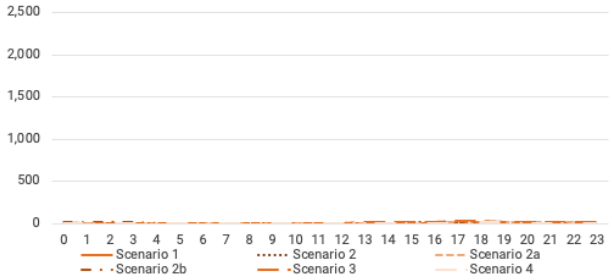
The personal EVSE average load shapes for all the scenarios are shown in Figure J-9. These charts show the expected average generation behavior from the personal EVSE, and the differences among the scenarios over the years. The behavior shapes for personal EVSE show the tendency for customers to start charging their vehicles upon returning home. The Goal Aligned scenario targets result in greater EV adoption and thus the dotted line in each chart represents the most pronounced personal EVSE charging pattern.

The Goal Aligned scenario was also used to examine the implications of mitigation. The Goal Aligned - Mitigation A (50% mitigation) scenario is reflected with the dashed line showing a lower peak during the early evening and higher peak in early morning hours as charging was shifted to later in the day. This is even more pronounced in the dash-dot line, which represents the Mitigation B (100%) mitigation scenario and shows a full shift of charging to later in the evening

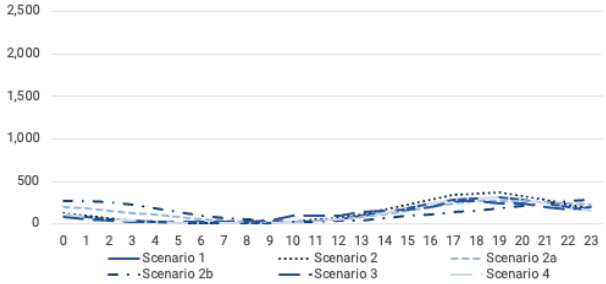
through early morning. Note these charts are showing average personal EVSE load at the premise and do not include losses.

Figure J-9: Personal EVSE average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala)

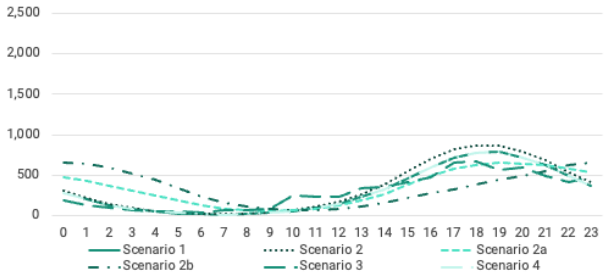
2025



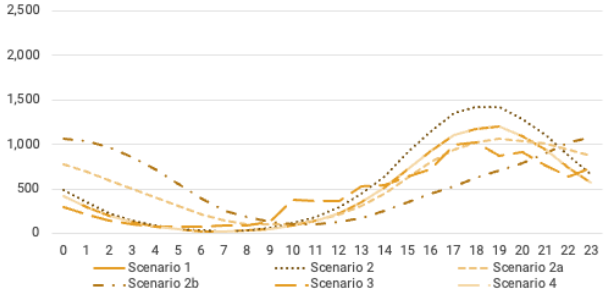
2030



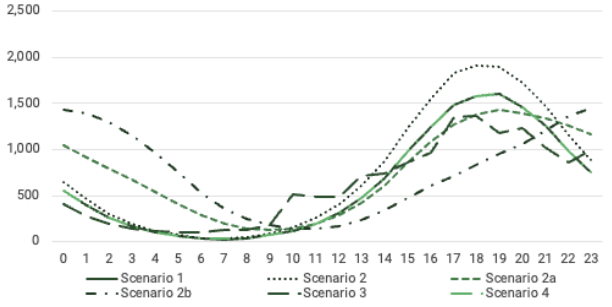
2035



2040



2045



2050

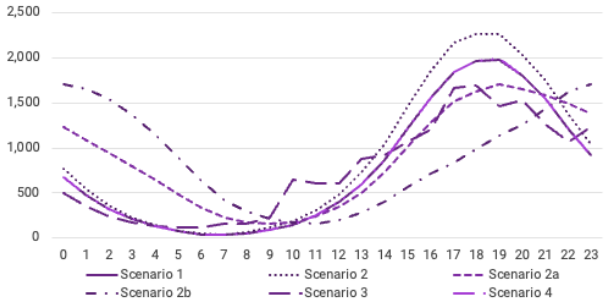
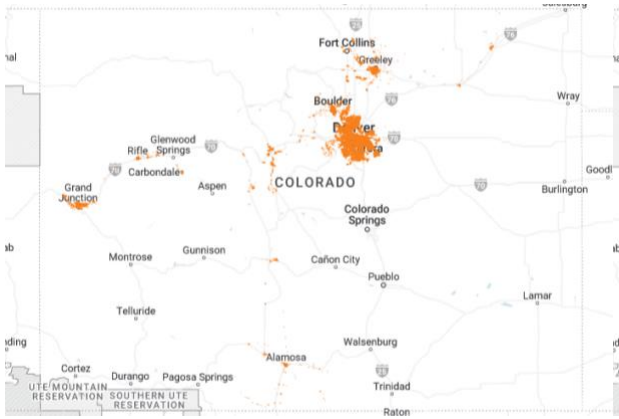


Figure J-10 shows the adoptions geographically.

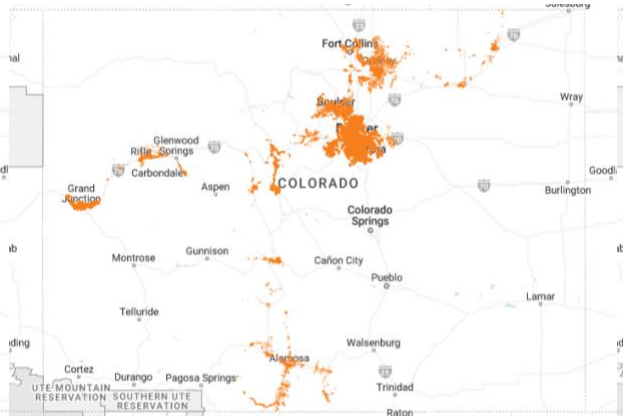
Figure J-10: Personal EVSE adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 (Source: Kevala)

Scenario 2: Policy Aligned

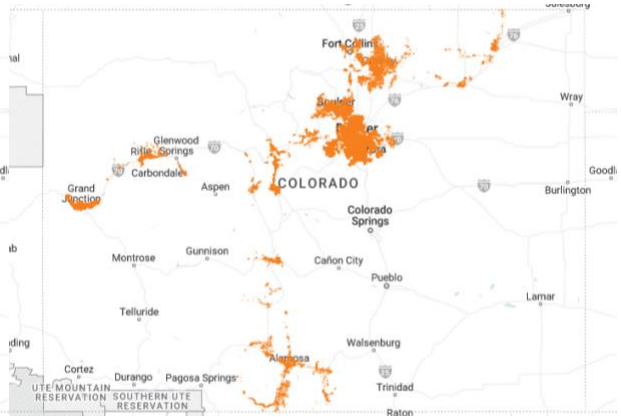
2025



2035

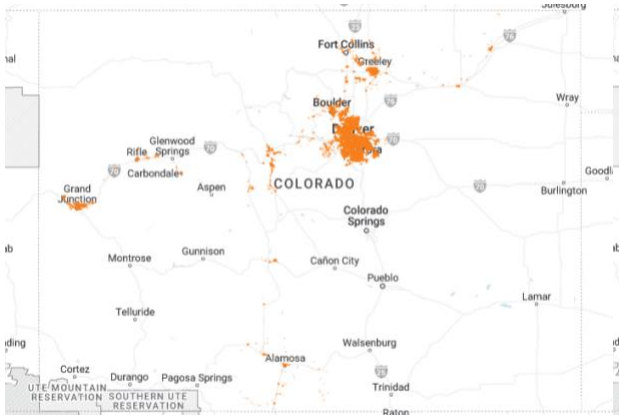


2045

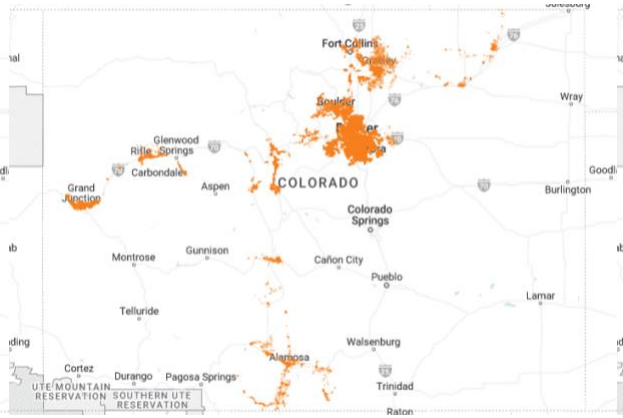


Scenario 3: Calibration

2025



2035



2045

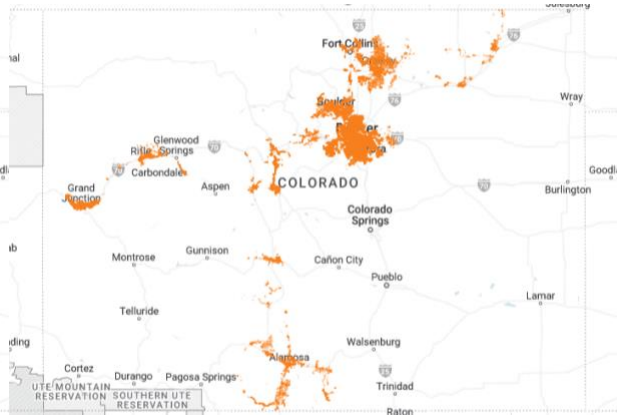


Figure J-11 and Figure J-12 are box and whisker charts showing the distribution of the contribution of personal EVSE to the feeder coincident peak and noncoincident peaks, respectively. The x-axis shows the study year while the y-axis shows the range of capacity contribution (kW) of the DER to system peak load.

The system peak charts show a fairly significant impact of personal EVSE load on system peak across Policy Aligned, Goal Aligned, Calibrated and Adoption Trajectory scenarios, particularly as EVSE growth persists over time. Goal Aligned Mitigation A (50%) and Goal Aligned Mitigation B (100%) show how effective managed charging can be in managing the risk as the level of impact is greatly reduced for system peak hours. Feeder peaks are less impacted by mitigation, which may be more driven by other DER loads that overlap with managed EVSE charging, such as heat pumps and water heating, which both tend to peak in the early winter hours.

Figure J-11: Distribution of personal EVSE load at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

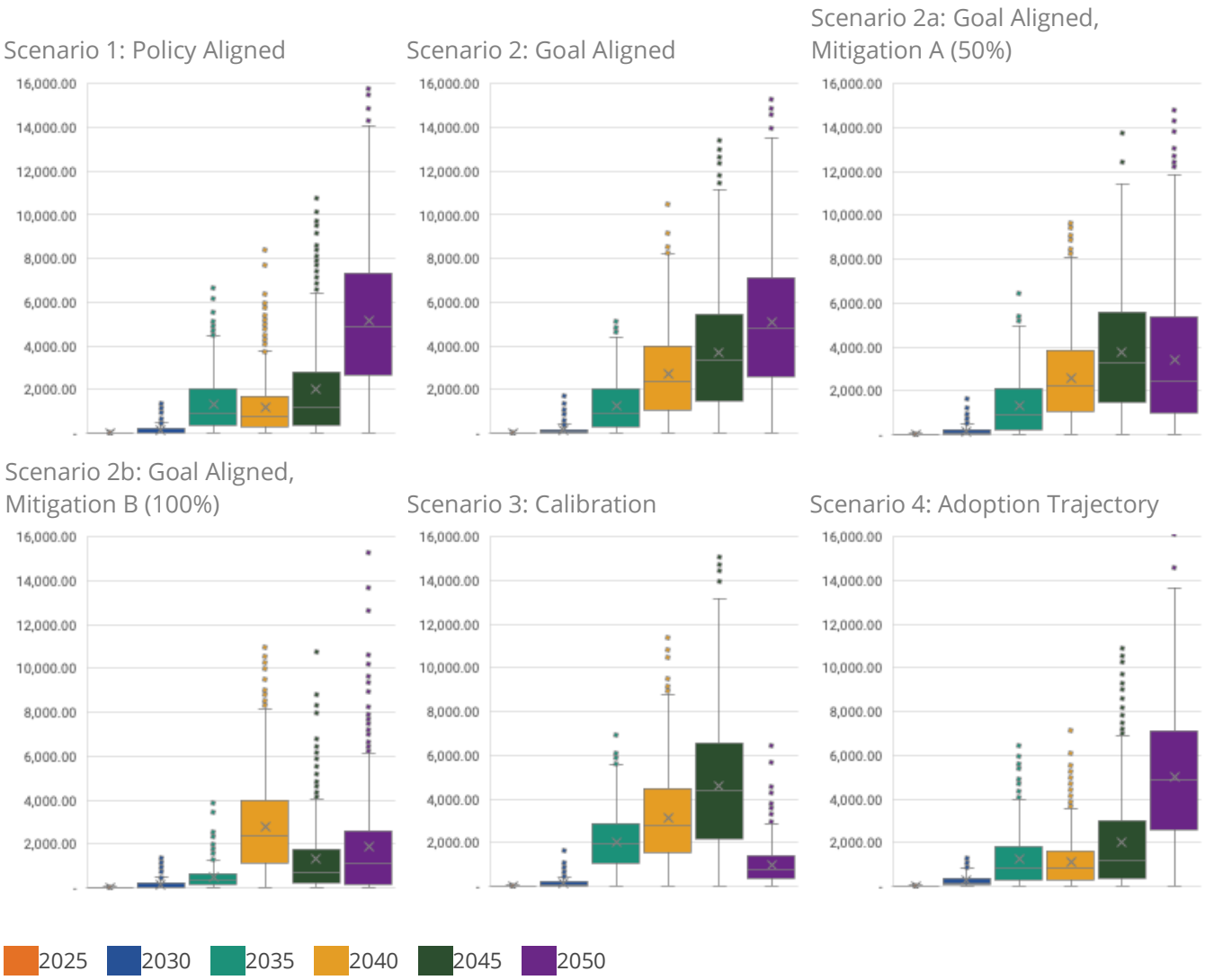


Figure J-12: Distribution of personal EVSE load at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

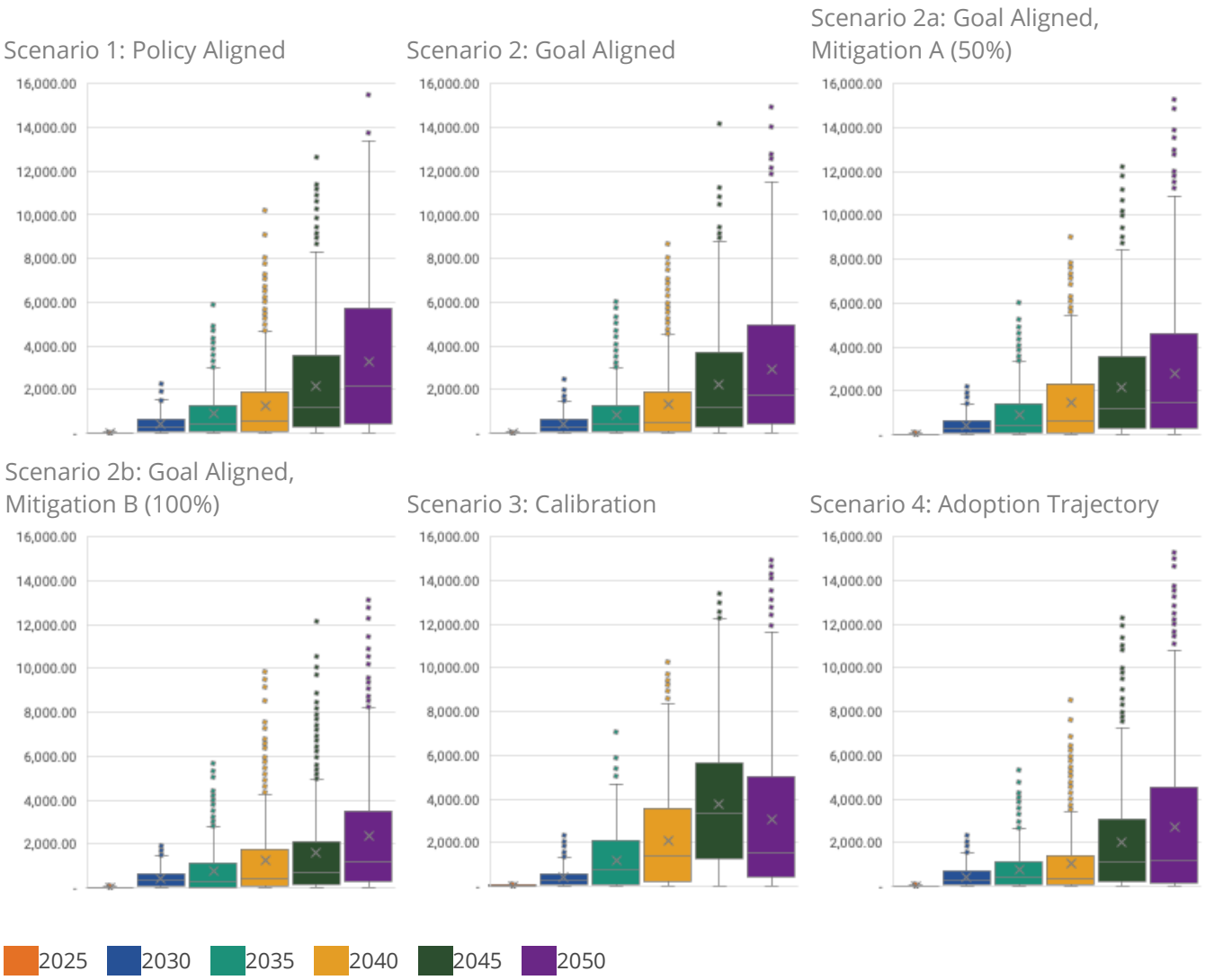
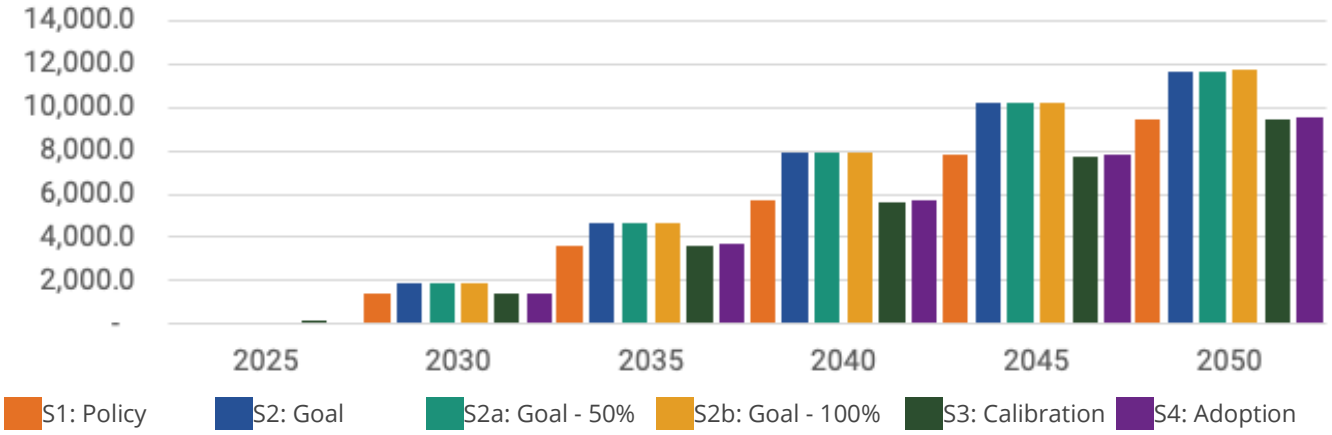


Figure J-13 shows the cumulative energy from personal EVSE for selected years by scenario.

Figure J-13: Cumulative energy (GWh) from personal EVSE by year and scenario: 2025-2050 (Source: Kevala)



J.4.2 Fleet

Figure J-14 shows incremental (i.e., the number each year) and cumulative fleet EVSE adoptions by scenario and year. These adoptions track with the targets shown in Figure J-2.

Figure J-14: Incremental and cumulative fleet adoptions by scenario and year: 2024-2050 (Source: Kevala)

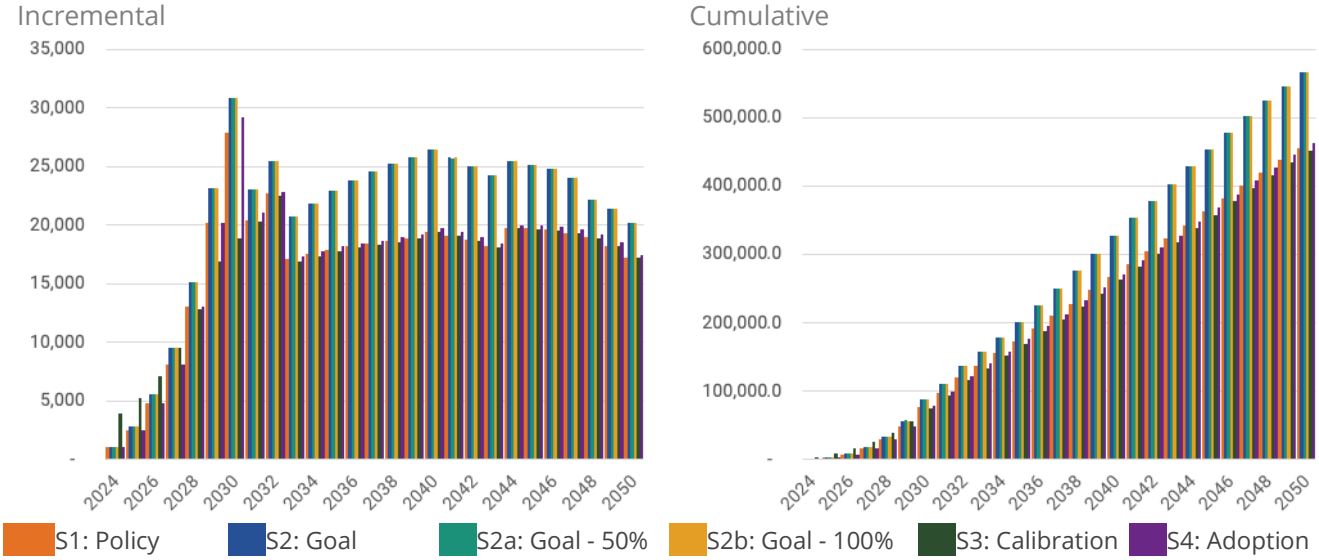
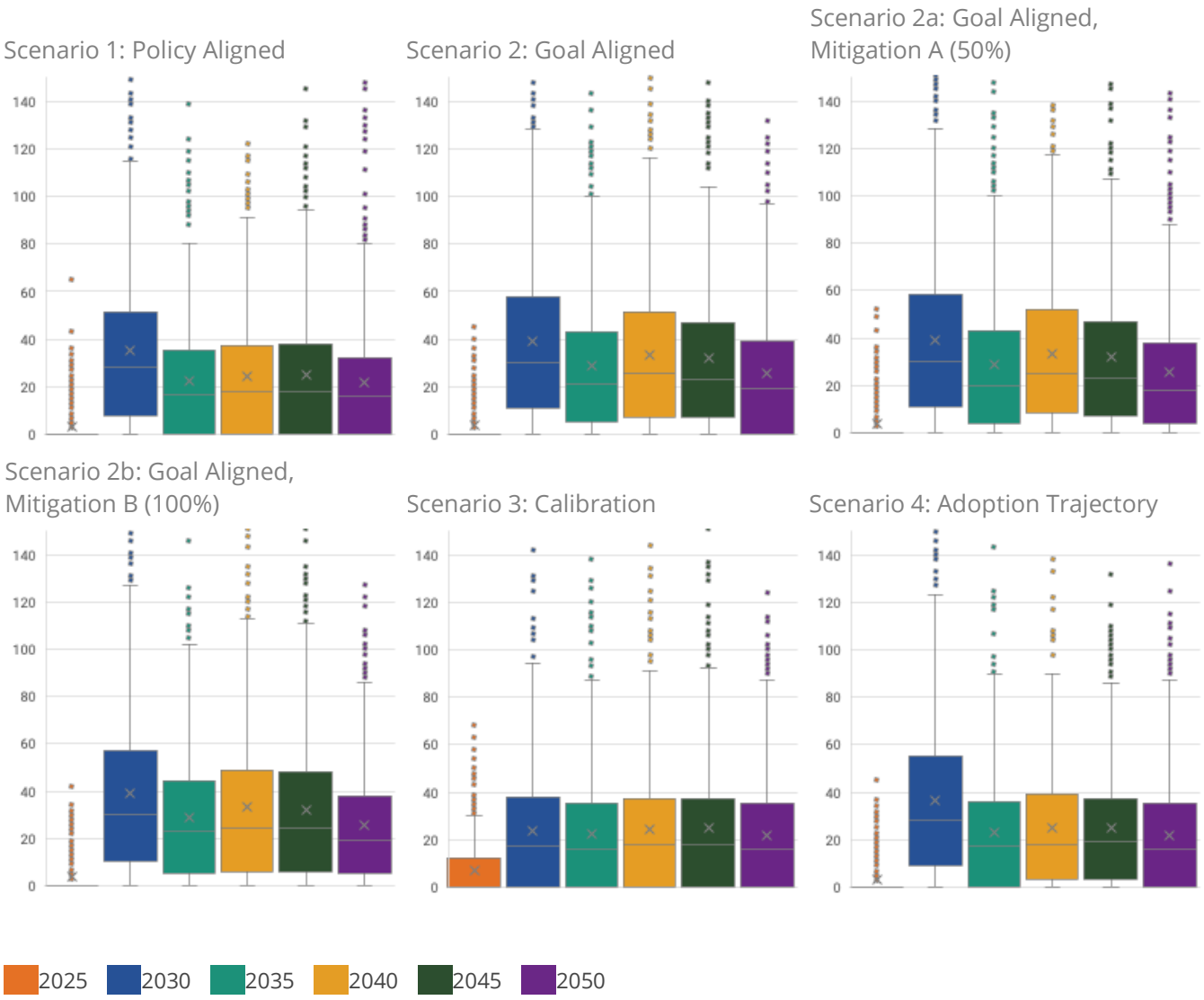


Figure J-15 shows the distribution of fleet EVSE adoptions on feeders by scenario and year in a series of box and whisker charts (see Figure F-6 and the accompanying text for more detail on this type of chart). The x-axis shows the study year while the y-axis shows the range of the number of fleet EVSE adoptions.

Figure J-15: Distribution of fleet EVSE adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)

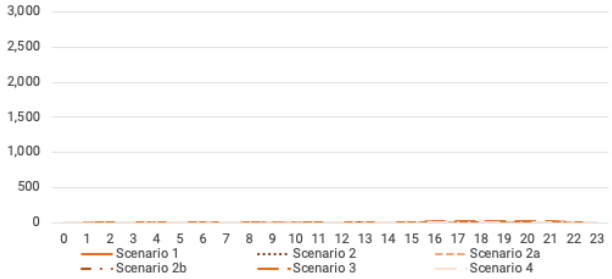


The fleet EVSE average load shapes for all the scenarios are shown in Figure J-16. These charts show the expected average consumption behavior from the fleet EVSE, and the differences among the scenarios over the years. The behavior shapes for fleet EVSE show the tendency for fleet EVs to start charging upon returning to the depot. Specifically, the charging is occurring during the early evening hours and ramping down as the vehicles reach full charge.

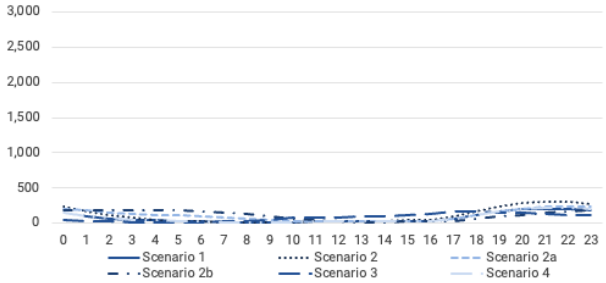
As noted above, the Goal Aligned scenario reflects the highest level of adoption of EVs and thus the greatest load, but it also demonstrates the benefits of mitigations through managed charging. Specifically, the dotted line is without mitigation, the dashed line is with 50% mitigation, and the dash-dot line shows 100% mitigation. The result is lower noncoincident peak loads during those early evening hours and more load seen in the late evening and early morning. Note these charts are showing average fleet EVSE load at the premise and do not include losses.

Figure J-16: Fleet average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala)

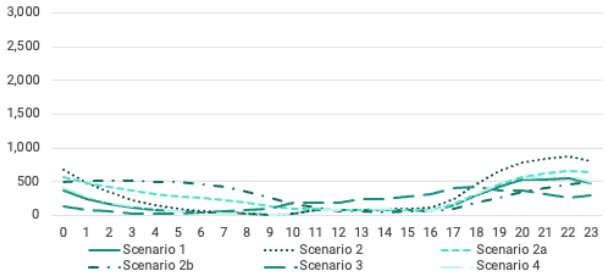
2025



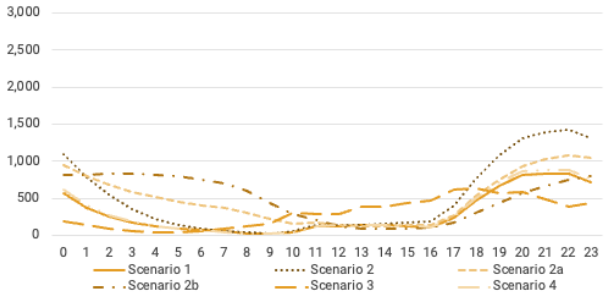
2030



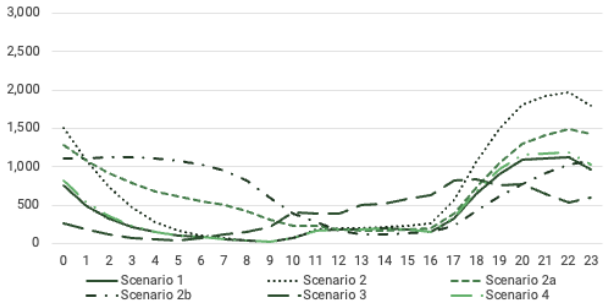
2035



2040



2045



2050

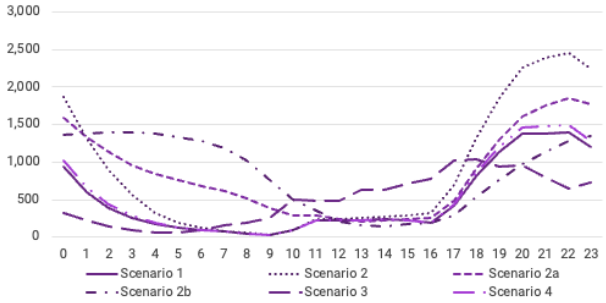


Figure J-17 shows the adoptions geographically. Across both scenarios, adoptions concentrate in the Denver metropolitan area early in the forecast and then move to more outlying areas by 2045.

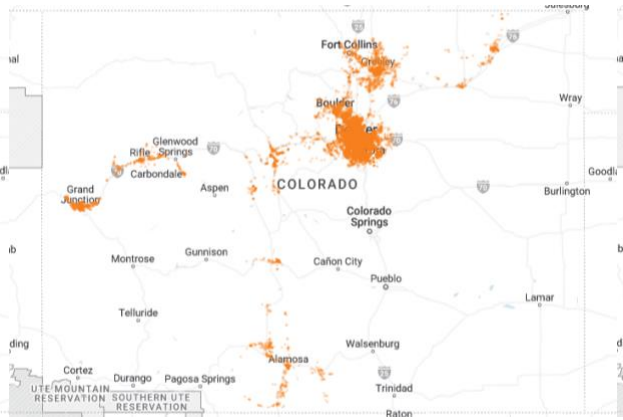
Figure J-17: Fleet adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045

Scenario 2: Policy Aligned

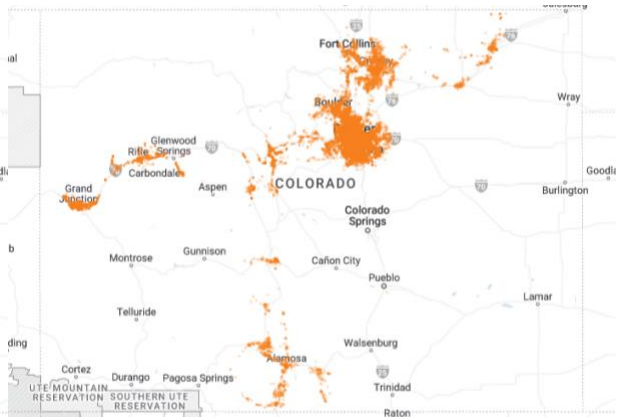
2025



2035

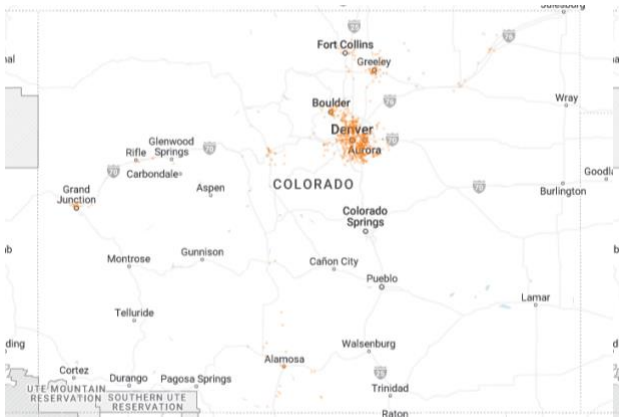


2045

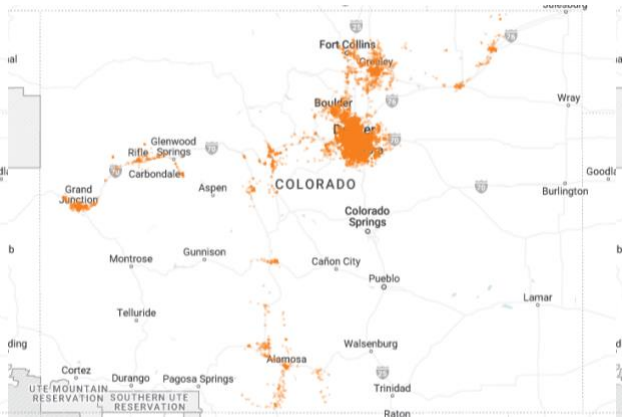


Scenario 3: Calibration

2025



2035



2045

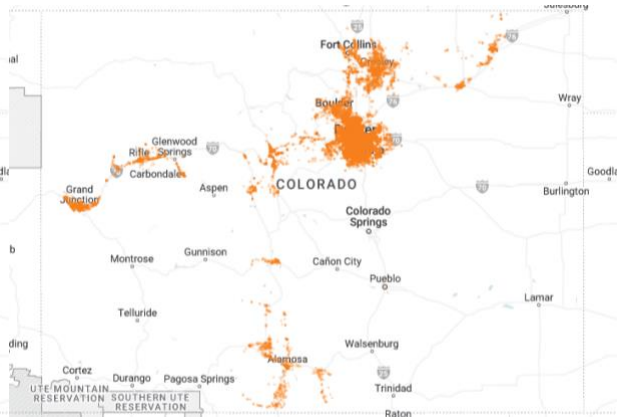


Figure J-18 and Figure J-19 are box and whisker charts showing the distribution of the contribution of fleet EVSE to the feeder coincident peak and noncoincident peaks, respectively. The x-axis shows the study year while the y-axis shows the range of capacity contribution (kW) of the DER to system peak load.

The system peak charts show a fairly significant impact of fleet EVSE load on system peak across the Policy Aligned, Goal Aligned, Calibration, and Adoption Trajectory scenarios, particularly as EVSE growth persists over time. As with personal EVSE, the Goal Aligned - Mitigation A (50%) and Goal Aligned - Mitigation B (100%) scenarios seem to influence system peak, particularly in the latter part of the forecast period (by 2050). Specifically, the difference in how effective managed charging can be in managing the risk as the level of impact is greatly reduced for system peak hours. Feeder peaks are less impacted by mitigation, which may be more driven by other DER loads that overlap with managed EVSE charging, such as heat pumps and water heating, which both tend to peak in the early winter hours. Nevertheless, the distribution of feeder impact is narrower among the mitigation scenarios.

Figure J-18: Distribution of fleet EVSE at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala)



Figure J-19: Distribution of fleet EVSE at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

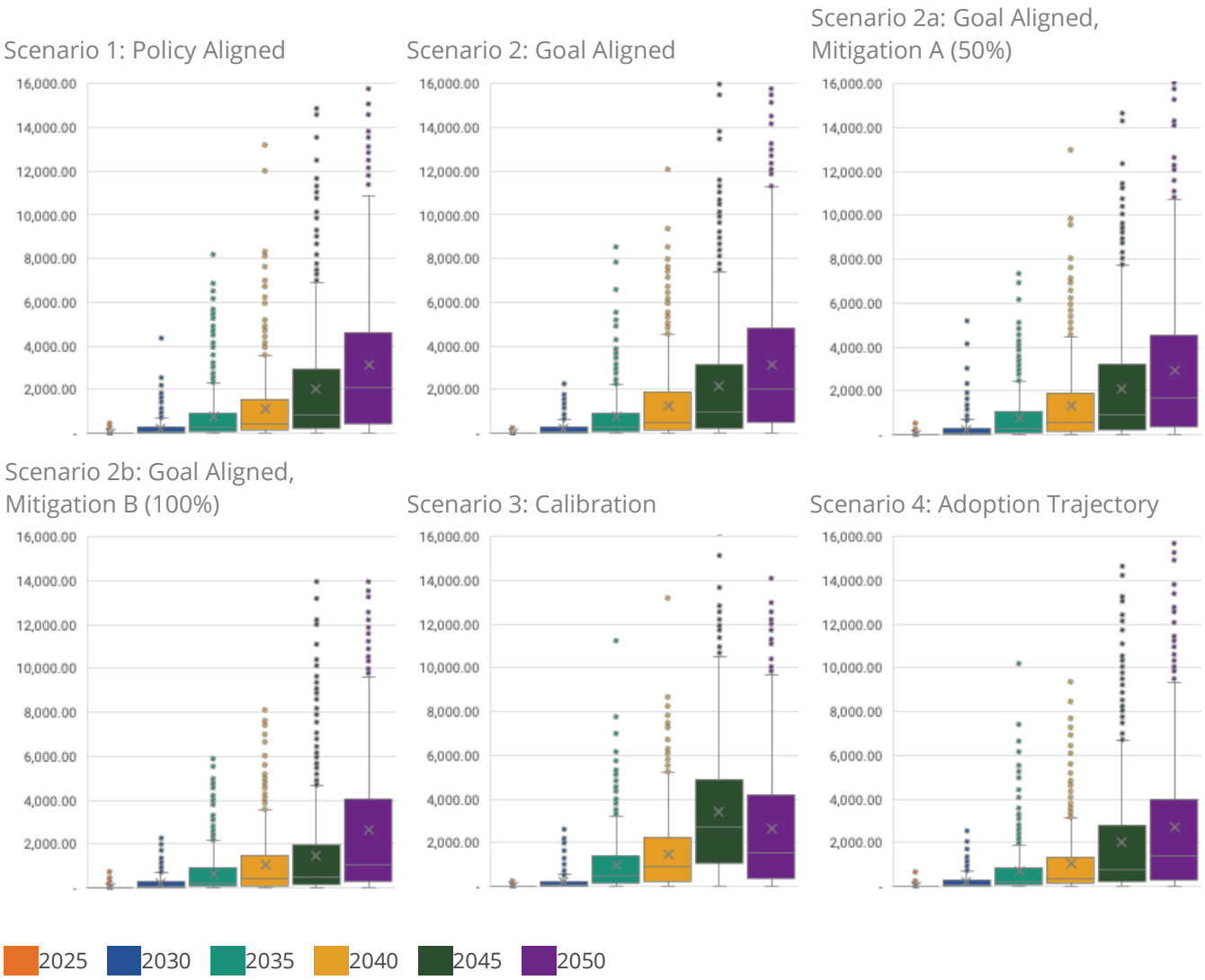
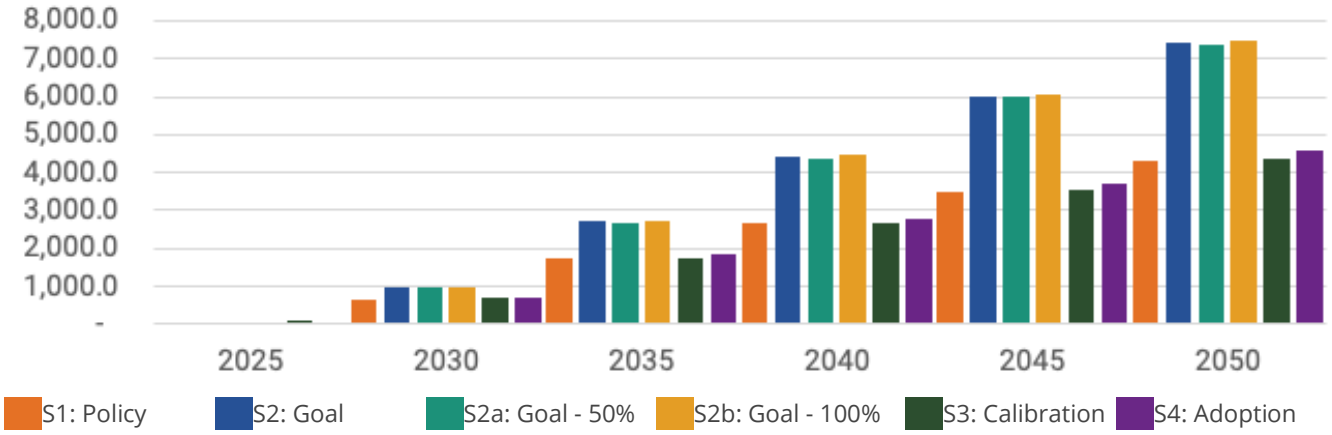


Figure J-20 shows the cumulative energy from fleet EVSE for selected years by scenario.

Figure J-20: Cumulative energy (GWh) from fleet EVSE by year and scenario: 2025-2050 (Source: Kevala)



J.4.3 PWC

Figure J-21 shows incremental (i.e., the number each year) and cumulative PWC EVSE adoptions by scenario and year. These adoptions track with the targets shown in Figure J-2.

Figure J-21: Incremental and cumulative PWC adoptions by scenario and year: 2024-2050 (Source: Kevala)

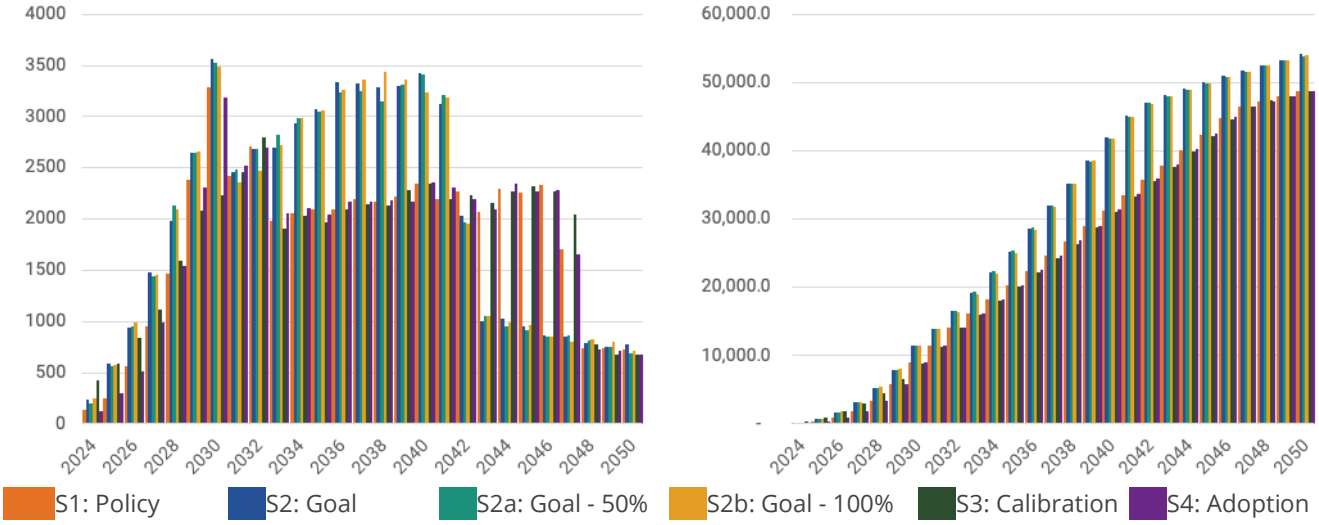


Figure J-22 shows the distribution of adoptions on feeders by scenario and year in a series of box and whisker charts (see Figure F-6 and the accompanying text for more detail on this type of chart). The x-axis shows the study year while the y-axis shows the range of the number of PWC EVSE adoptions.

Figure J-22: Distribution of PWC EVSE adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)

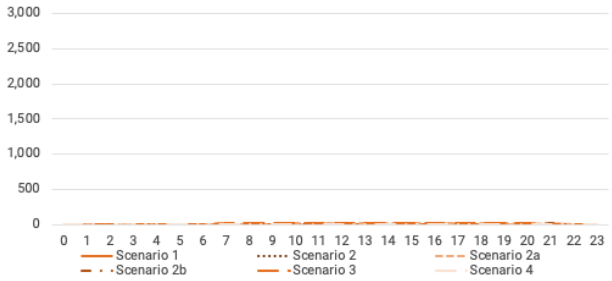


The PWC EVSE average load shapes for all the scenarios are shown in Figure J-23. These charts show the expected average load behavior from the PWC EVSE, and the differences among the scenarios over the years. The PWC shapes are very different from the personal and fleet EVSE loads, namely because these premises are seeing vehicles arrive throughout the day and, in the case of workplace charging, occurring in the mid-morning. The profile shows an increase in the morning, hovering constant around 1000 to 2000 hours and then sharply declining.

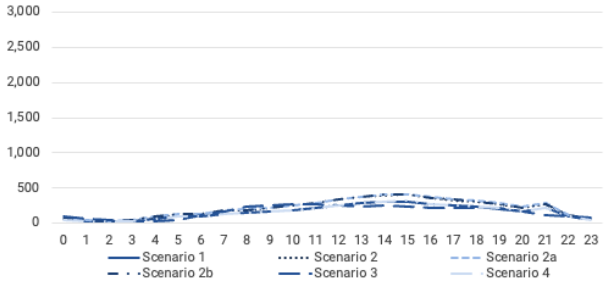
The other item of note is that the mitigation scenarios have no impact on PWC charging behavior because Kevala assumes these loads are not sensitive to such signals. This is particularly true for corridor charging, where vehicles are arriving off main thoroughfares with the goal of charging quickly, and workplace charging, where vehicles are arriving onsite and stay onsite during the work hours. Note these charts are showing average PWC EVSE load at the premise and do not include losses.

Figure J-23: PWC EVSE average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala)

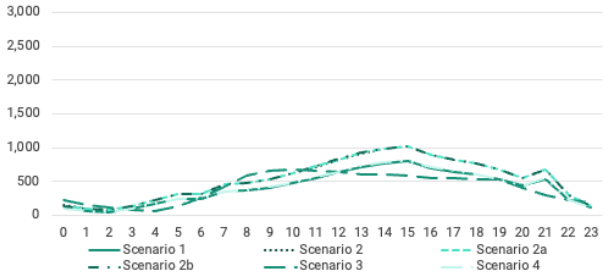
2025



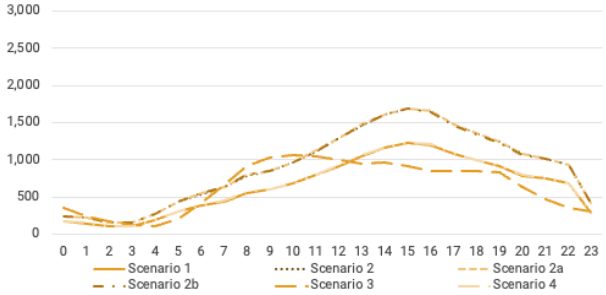
2030



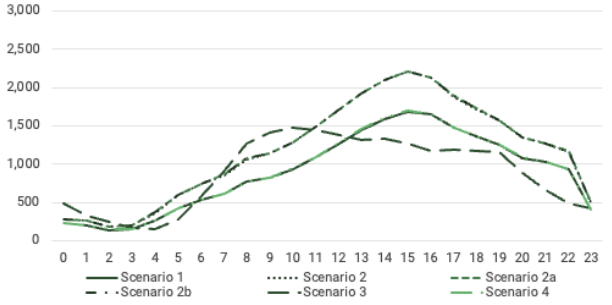
2035



2040



2045



2050

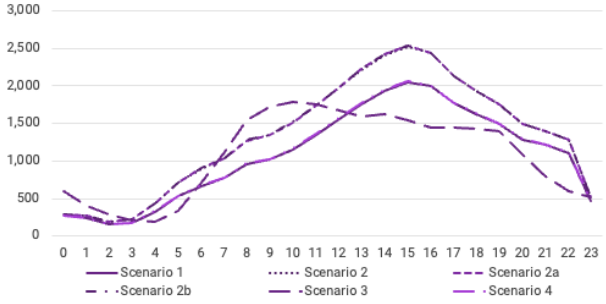
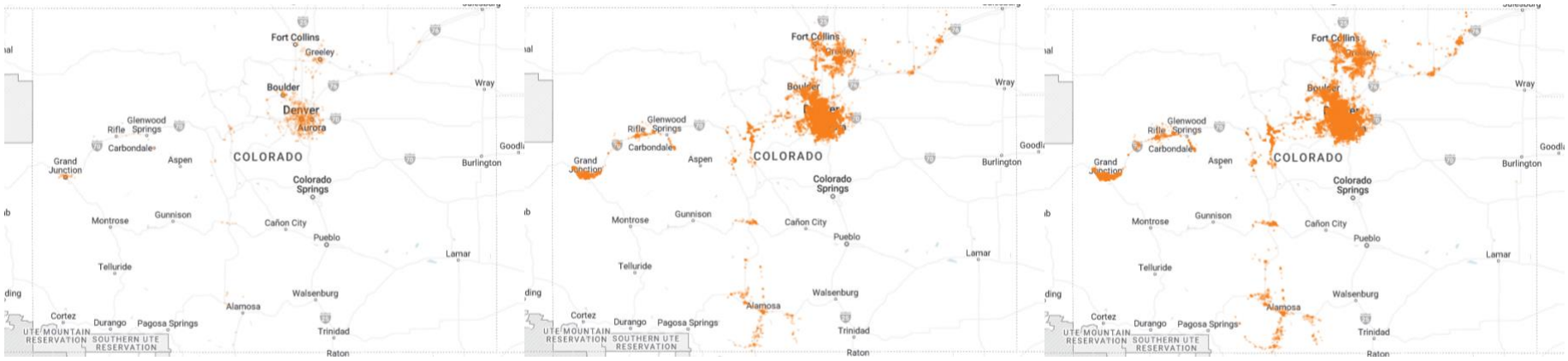


Figure J-24 shows the adoptions geographically. As these diagrams show, the adoptions are more concentrated around metropolitan areas, reflecting workplace charging, and interstates, reflecting corridor charging.

Figure J-24: PWC adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 (Source: Kevala)

Scenario 2: Policy Aligned

2025 2035 2045



Scenario 3: Calibration

2025 2035 2045

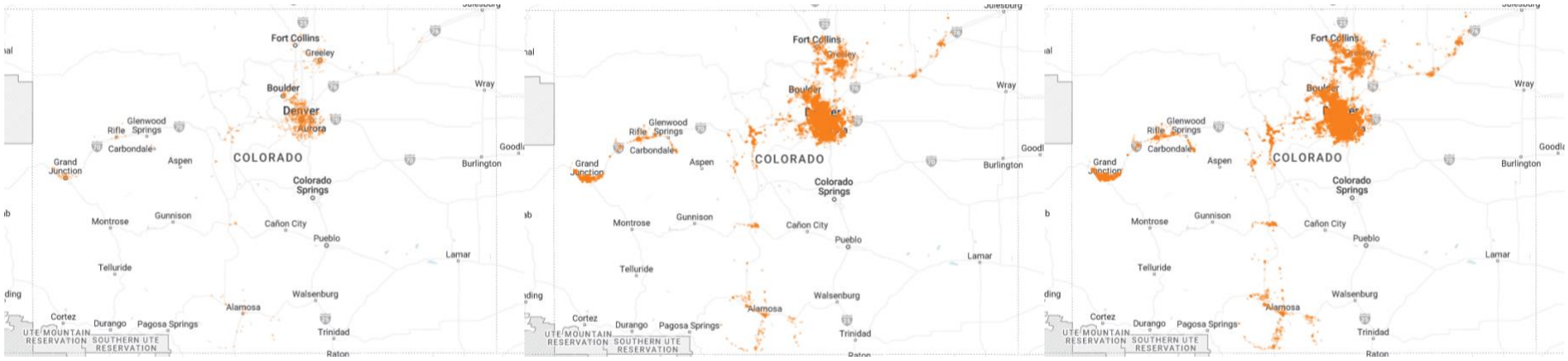


Figure J-25 and Figure J-26 are box and whisker charts showing the distribution of the contribution of PWC EVSE to the feeder coincident peak and noncoincident peaks, respectively. The x-axis shows the study year while the y-axis shows the range of capacity contribution (kW) of the DER to system peak load.

The system peak charts show an impact from PWC load on system peak across Policy Aligned, Goal Aligned, Calibration, and Adoption Trajectory scenarios, particularly as EVSE growth persists over time. The impact on the system peak from the Goal Aligned - Mitigation A (50%) and Goal Aligned - Mitigation B (100%) scenarios does change from one scenario to another; however, this is due to the change in the timing of the peaks being driven by other DERs rather than the impact of mitigations on PWC because no managed charging was assumed for this EVSE group. Feeder peaks are also impacted by PWC EVSE loads, but the changes across years and scenarios is driven by the number of vehicles.

Figure J-25: Distribution of PWC EVSE load at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

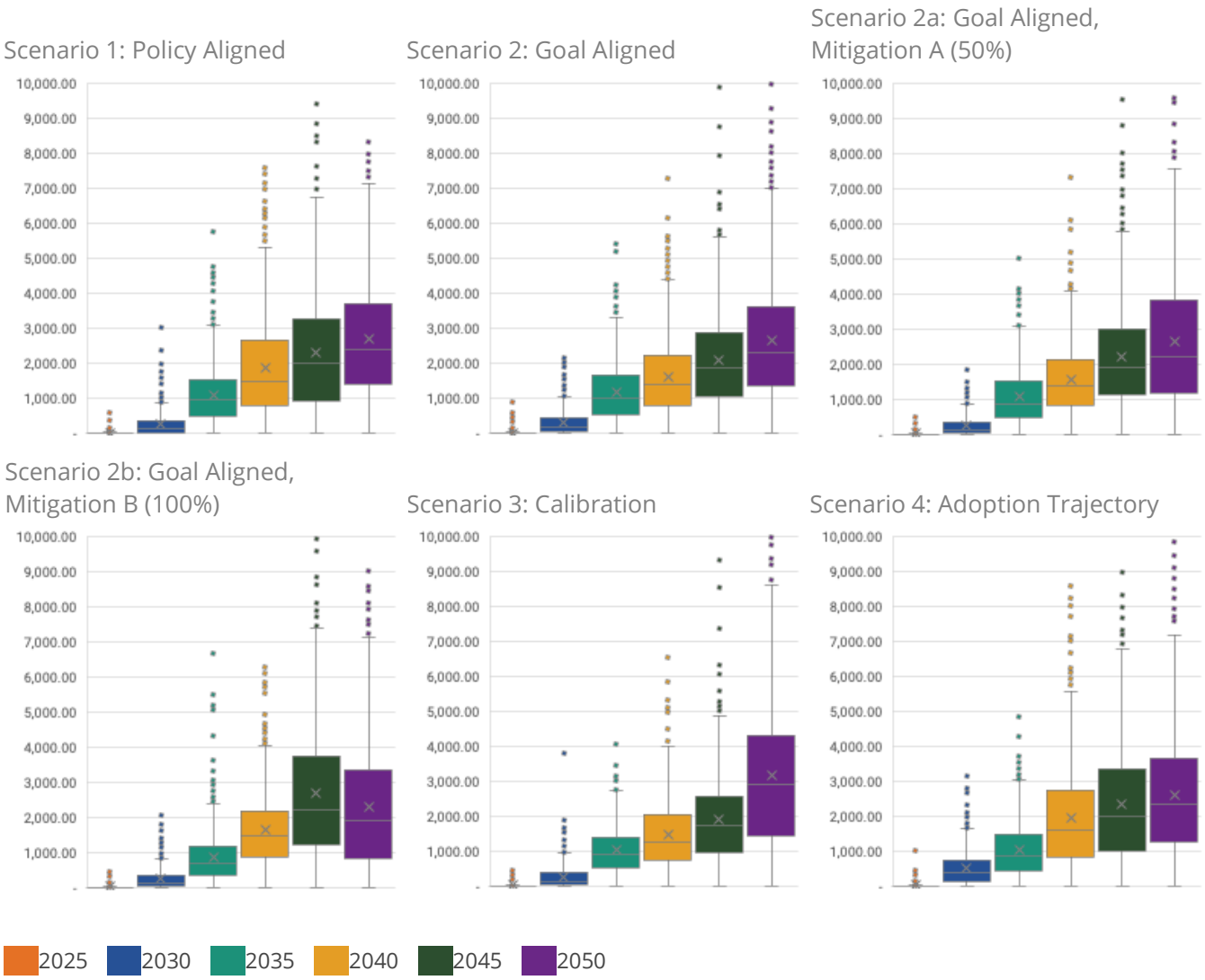


Figure J-26: Distribution of PWC EVSE load at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

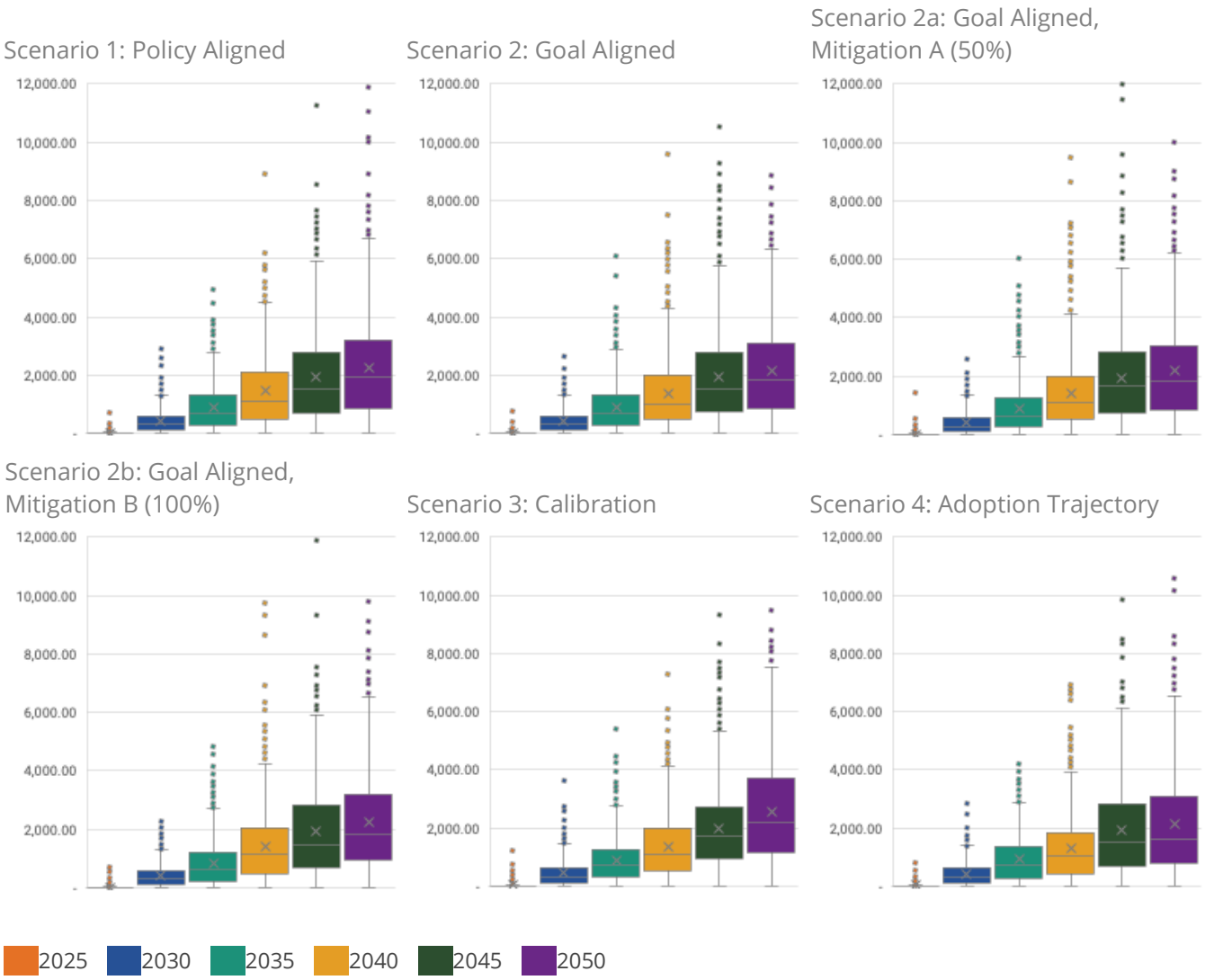
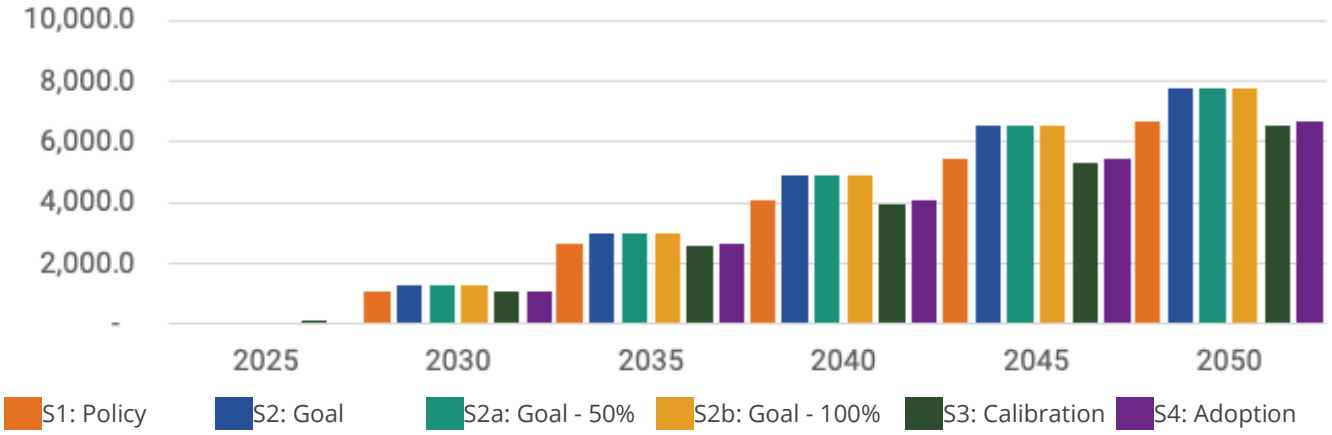


Figure J-27 shows the cumulative energy from fleet EVSE for selected years by scenario.

Figure J-27: Cumulative energy (GWh) from fleet EVSE by year and scenario: 2025-2050 (Source: Kevala)



The following are key findings from Kevala's analysis of the EV and EVSE results:

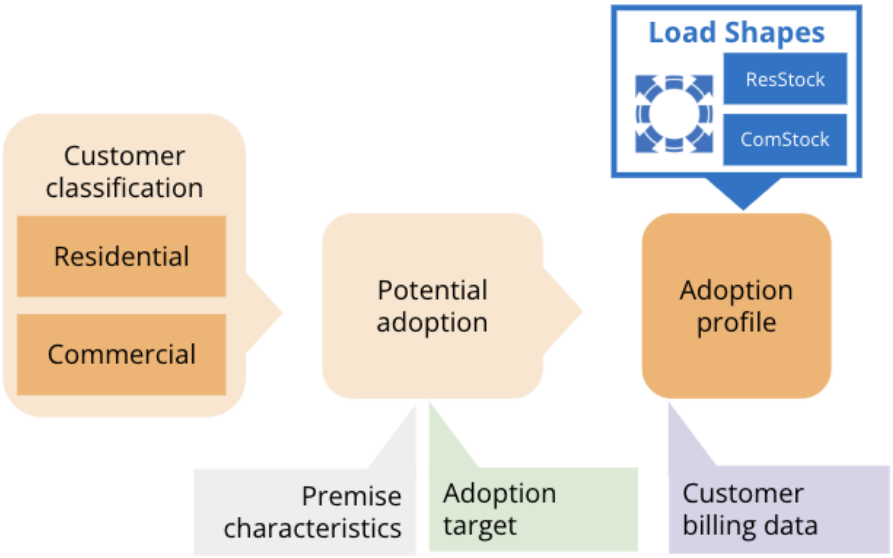
- The EVSE peak day load shapes show how the timing of the system peak may be influenced by EVSE adoption as EVs arrive at customer homes or depots for overnight charging.
- Managed charging can help mitigate the timing of the charging and reduce the impact of the EVSE adoptions on the distribution grid.

Appendix K. Heat Pump Water Heating Modeling Methodology and Additional Results

K.1 Approach

Kevala's heat pump water heating (HPWH) methodology reflects the increasing shift from traditional water heating systems relying on fossil fuels to those powered by electricity. Kevala's approach identified customers by sector (i.e., residential and commercial) eligible to switch from gas water heating to HPWH and then estimated the size, behavior, and adoption for HPWH systems following the flow shown in Figure K-1.

Figure K-1: Flow diagram of HPWH modeling (Source: Kevala)



K.1.1 Sizing and Behavior

Kevala leveraged water heating end-use profiles from NREL's ResStock and ComStock datasets.[63] From NREL's dataset, Kevala selected building profiles on a county-by-county basis driven by a premise's total annual load derived from monthly energy bills. Representative buildings from ResStock were used for premises with a residential revenue class, while ComStock profiles were selected for commercial revenue classes (including Government). In cases where fewer than 50 representative buildings were available, Kevala expanded from a larger statewide pool of candidate building types.

[63] NREL's ResStock and ComStock datasets model geographically specific building types with load profiles that account for local variations in water usage and heating technology types. To represent the HPWH end-use curves of residential buildings, Kevala used the 2022 1.1 ResStock's Upgrade 6 package, which specifically models the impact of upgrading from traditional water heaters to HPWH.

For residential customers, Kevala used premise-level billing data to determine whether a given premise was served by natural gas, electricity, or both, and selected a building profile matched on a service basis. For example, approximately 1 million customers were matched with ResStock buildings with natural gas water heating, while approximately 350,000 customers were matched with building profiles powered by electric or propane water heating.

Kevala assumed that all commercial premises were heated with natural gas, and matched profiles to ComStock. This aligned with the PSCo-provided assumption that 94% of the commercial build stock in 2024 had gas water heating.

K.1.2 Adoption

Premises were deemed eligible for HPWH adoption if:

1. Revenue class was residential or commercial
2. Had a modeled water heating fuel type that was not electricity at the start of the forecast

If eligible for adoption, each premise received an adoption propensity score for its relative likelihood to adopt a HPWH for each year of the scenario. A single adoption was counted even if multiple HPWH units were adopted by a single customer to meet the hot water load on the premise. Once the customer switched from gas to electric water heating, no additional adoptions were considered for that customer through the remaining forecast years.

Because Boulder and Denver have strong heating electrification policies for existing and new-build premises,[64] adoption scores were adjusted accordingly. For example, if a premise was both a new build and located within these cities, its propensity to adopt was, on average, four times as likely to adopt an HPWH as an existing building outside of Boulder or Denver.

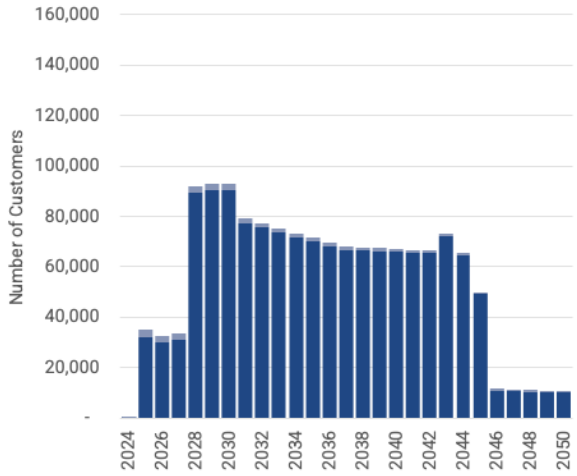
Once adoption propensity scores were assigned for all eligible premises, Kevala ranked the eligible premises according to their score value and simulated adoption for each year in the forecast. Each year, adopting premises were selected one at a time from all eligible premises that had not already adopted HPWH until the service territory's top-down yearly target capacity was reached.

Figure K-2 shows the annual and cumulative HPWH targets used for this study by scenario. PSCo provided targets broken out between the residential and commercial customer classes.

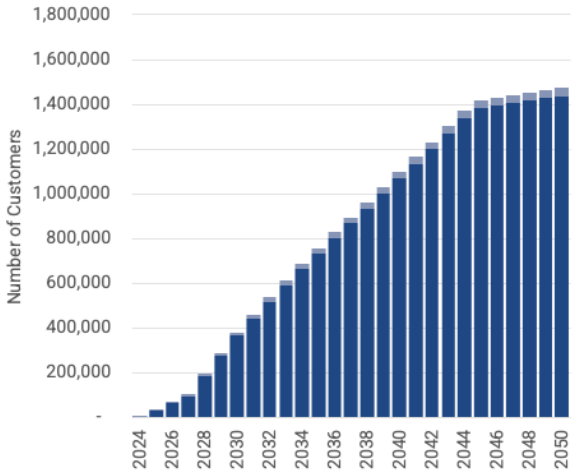
[64] For more information on these policies and mandates, see: Denver Council Bill 21-1310 and the City of Boulder 2024 Energy Conservation Code Update.

Figure K-2: Annual HPWH target adoptions by class, scenario, and year: 2024-2050 (Sources: PSCo, Kevala)

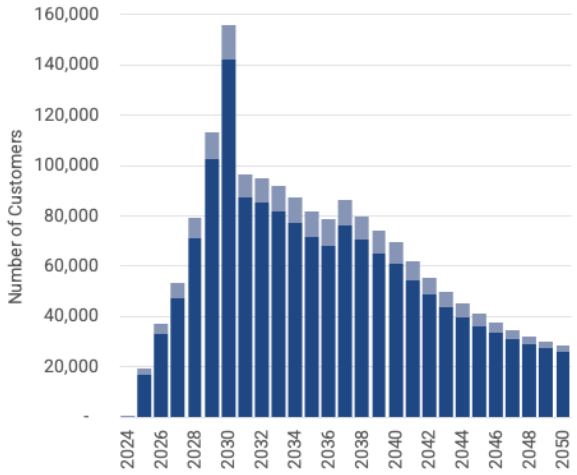
Scenario 1: Policy Aligned - Incremental



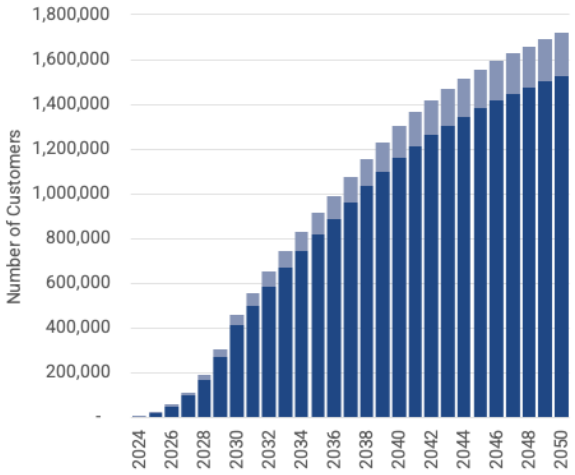
Scenario 1: Policy Aligned - Cumulative



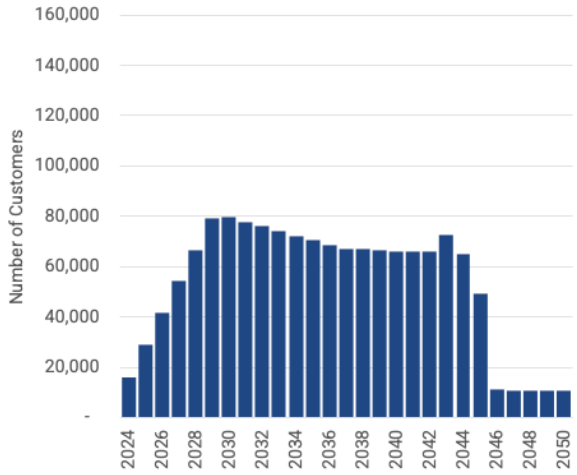
Scenario 2: Goal Aligned - Incremental



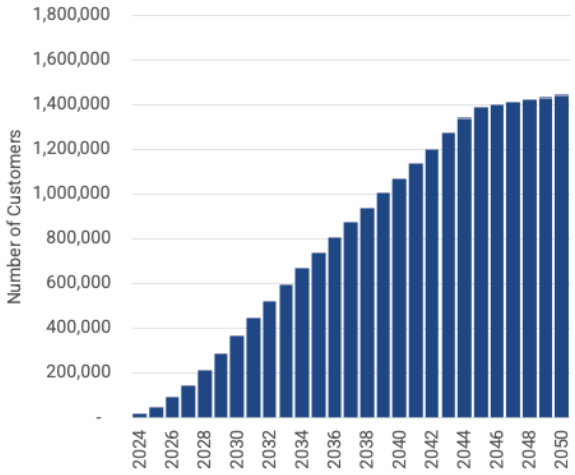
Scenario 2: Goal Aligned - Cumulative



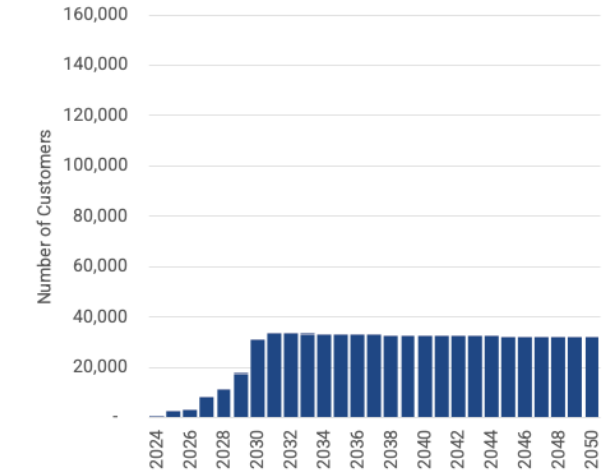
Scenario 3: Calibration- Incremental



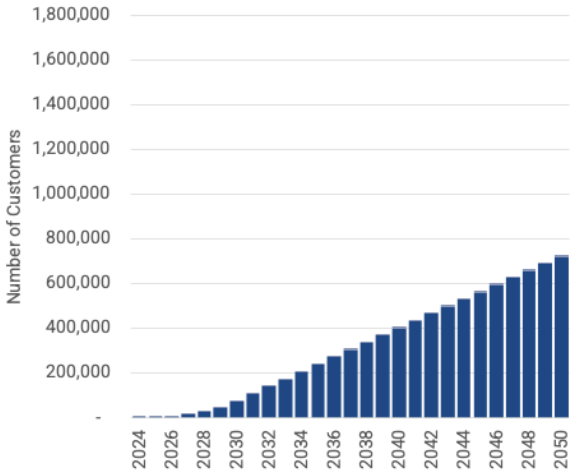
Scenario 3: Calibration - Cumulative



Scenario 4: Adoption Trajectory- Incremental



Scenario 4: Adoption Trajectory - Cumulative



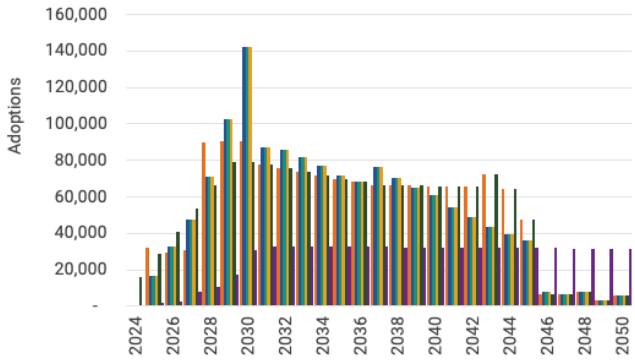
Residential Commercial

K.2 Analysis and Results

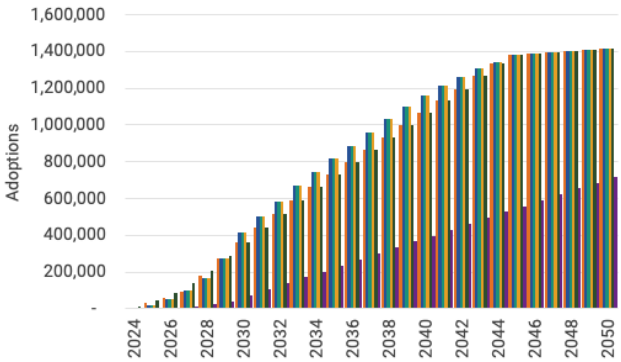
Figure K-3 shows the incremental and cumulative HPWH adoptions by class, scenario, and year. These adoptions track with the targets shown in Figure K-2.

Figure K-3: HPWH adoptions by class, scenario, and year: 2024-2050 (Source: Kevala)

Residential - Incremental



Residential - Cumulative



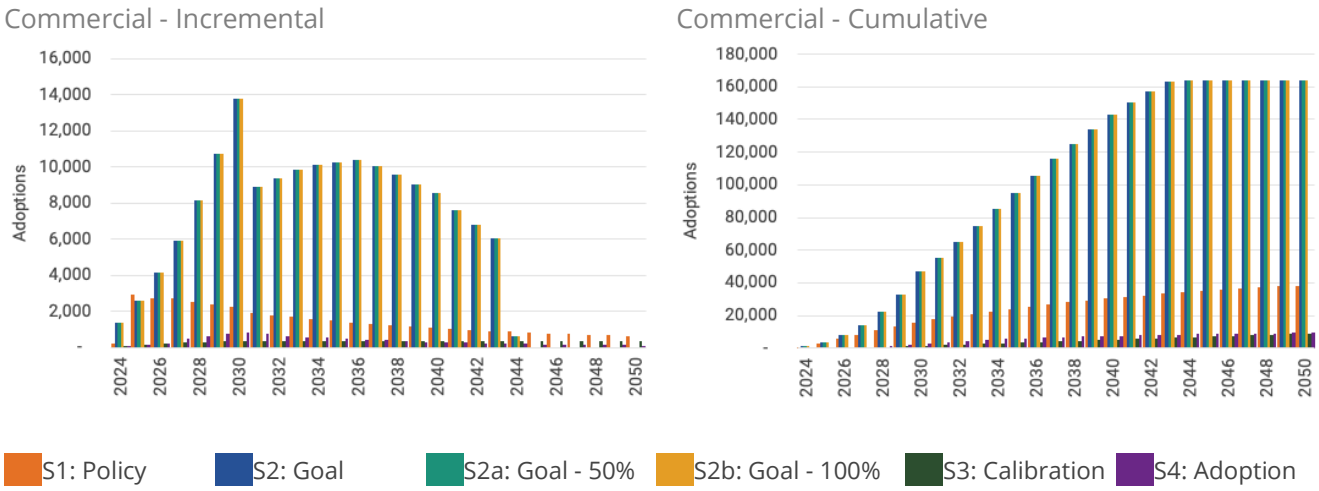


Figure K-4 and Figure K-5 show the distribution of adoptions on feeders by class, scenario, and year in a series of box and whisker charts (see Figure F-6 and the accompanying text for more detail on this type of chart). The x-axis shows the study year while the y-axis shows the range of the number of HPWH adoptions. The adoptions follow the targets shown above, with the Goal Aligned scenarios having the greatest HPWH adoptions for both residential and commercial customers. Note also that the number of commercial adoptions is much lower in the Calibration and Adoption Trajectory scenarios compared to the Policy and Goal Aligned scenarios.

Figure K-4: Distribution of residential HWPH adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)

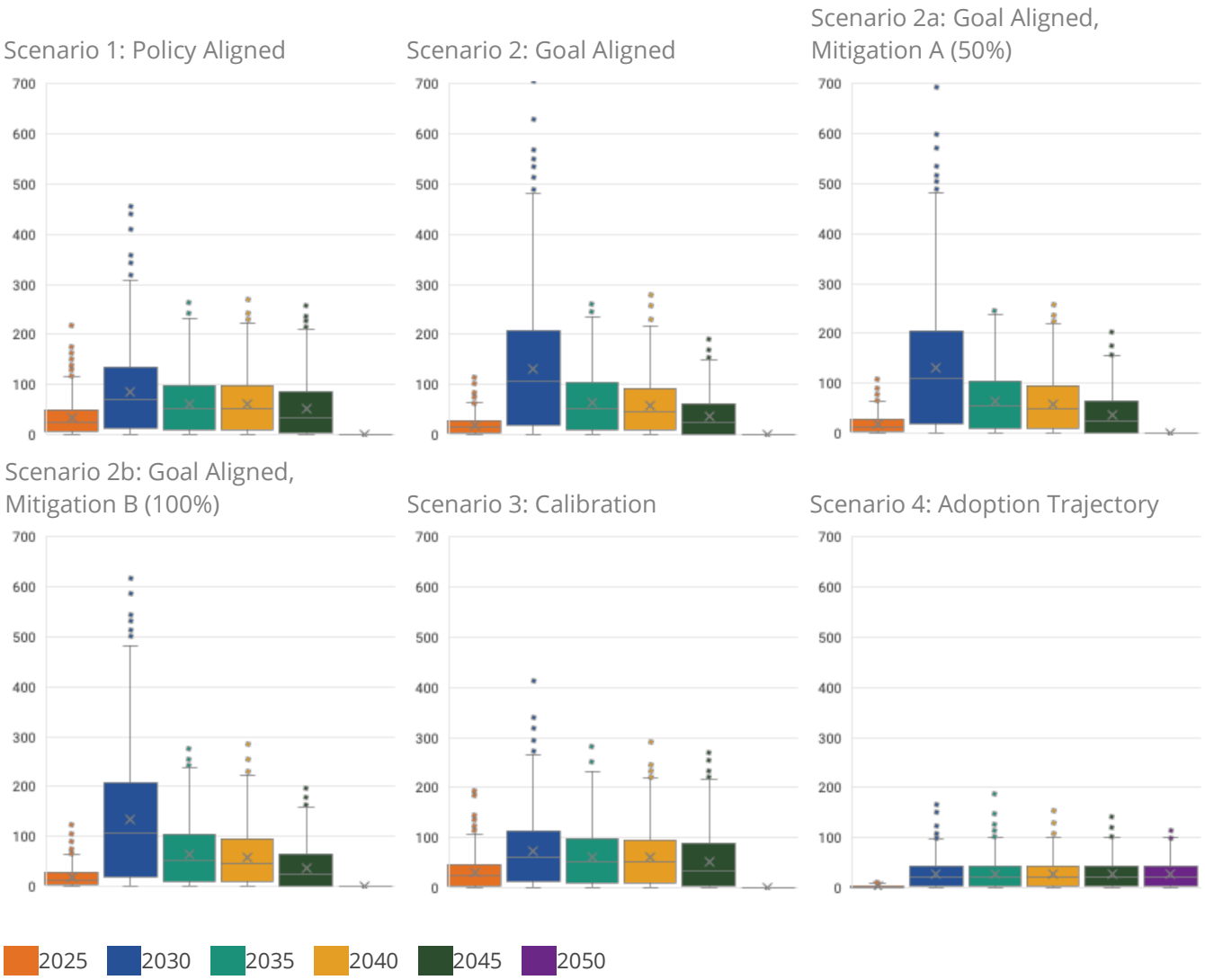
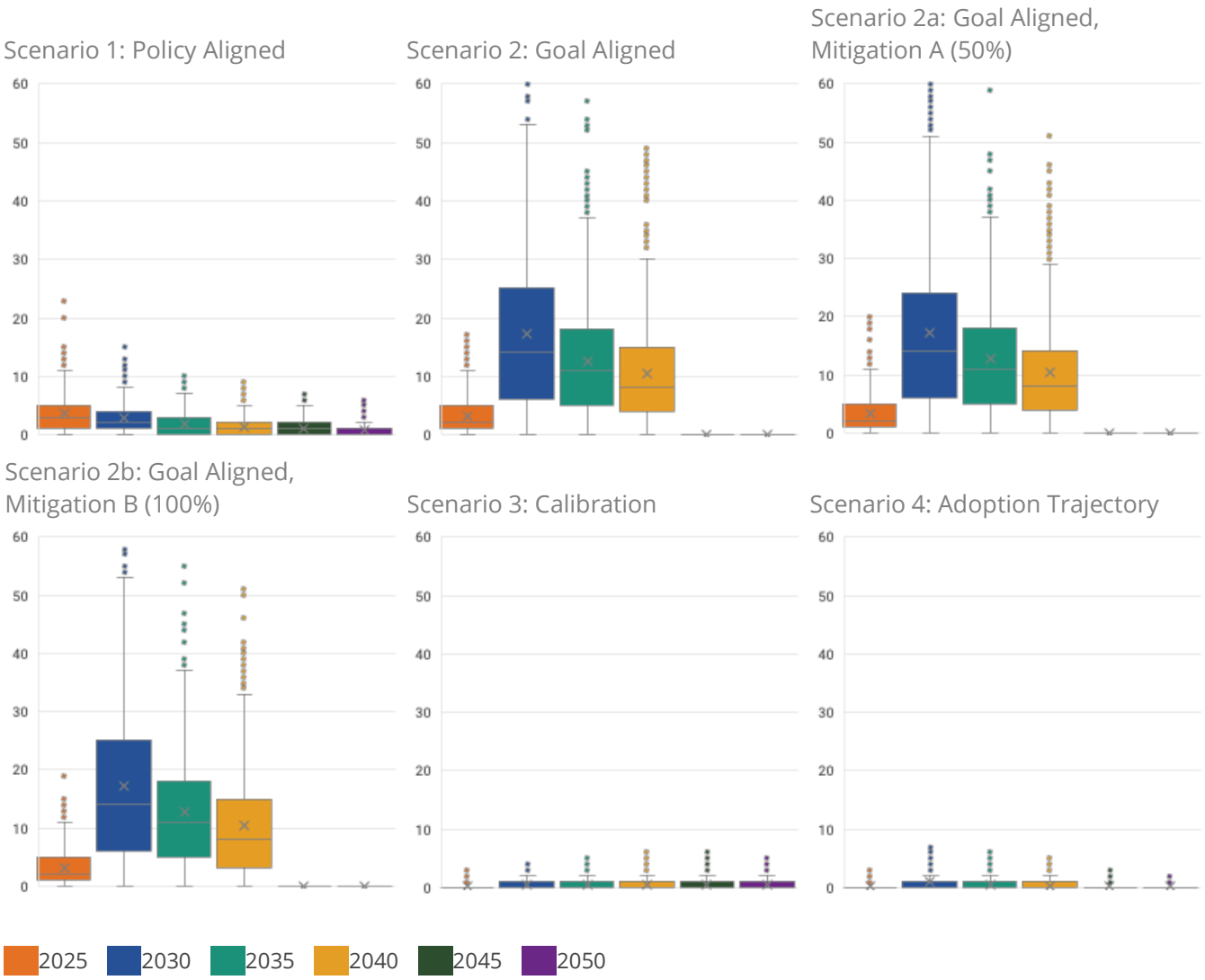


Figure K-5: Distribution of commercial HWPH adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)



The HPWH average load shapes for all the scenarios are shown in Figure K-6. These charts show the expected average load behavior from HPWH, and the differences among the scenarios over the years. The shape is indicative of water heater loads, with peaks usually occurring in the morning hours and staying somewhat constant over the day and then declining in the early morning hours. Note these charts are showing average HPWH load at the premise and do not include losses.

Figure K-6: HPWH average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala)

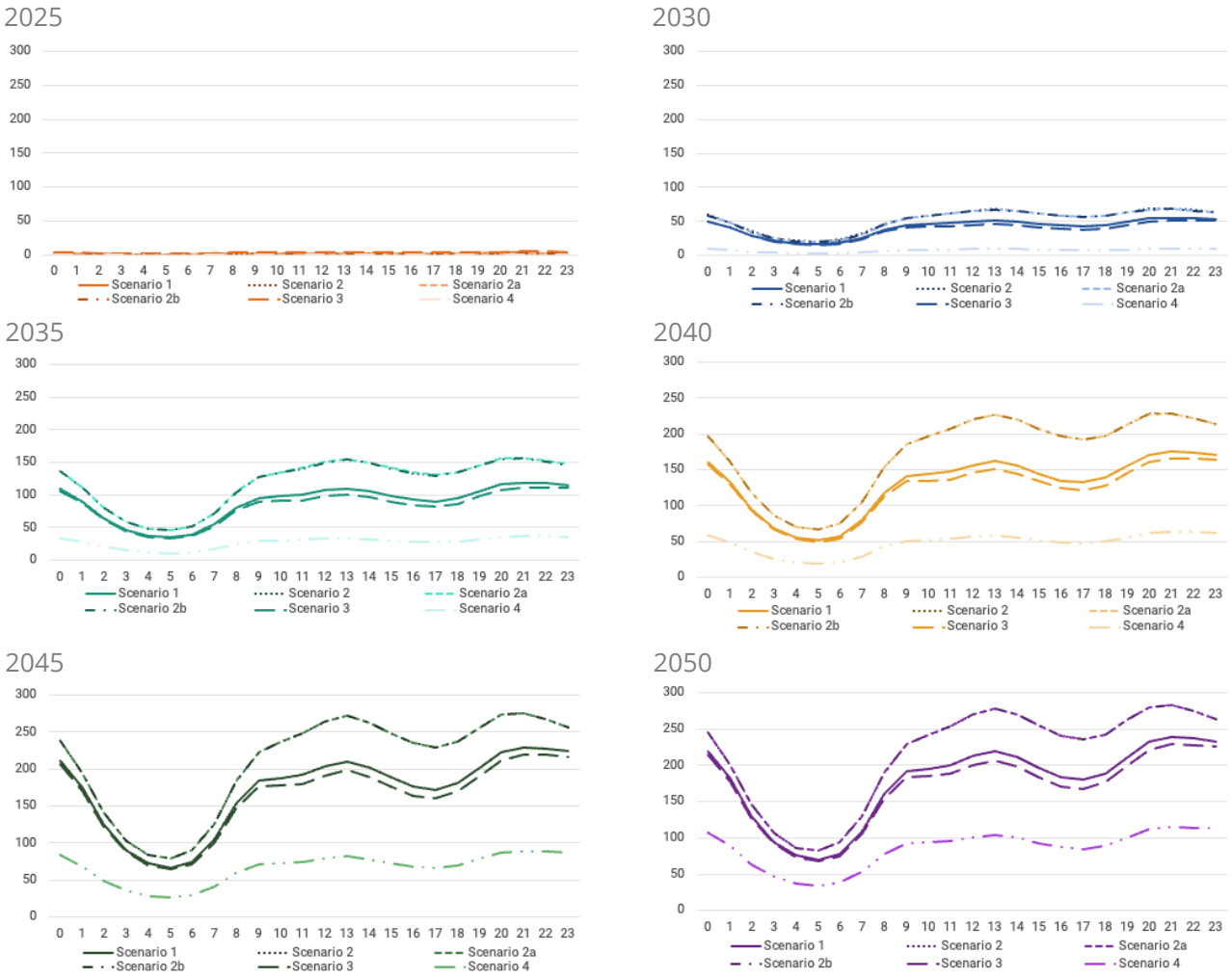
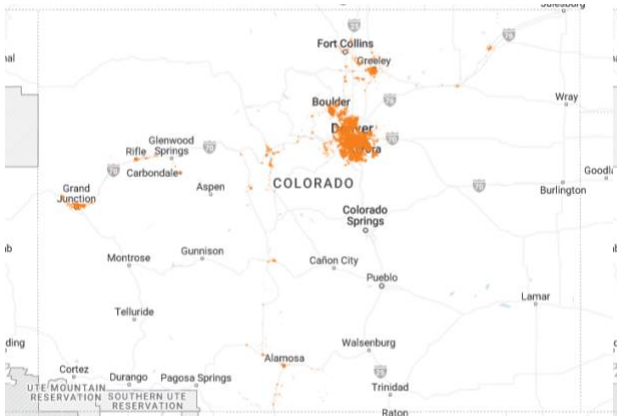


Figure K-7 shows the adoptions geographically. As these diagrams show, the adoptions early on (2025) are concentrated in the metropolitan areas where there are more significant concentrations of residential customers. Over time other areas see more adoption but remain concentrated in urban and suburban areas.

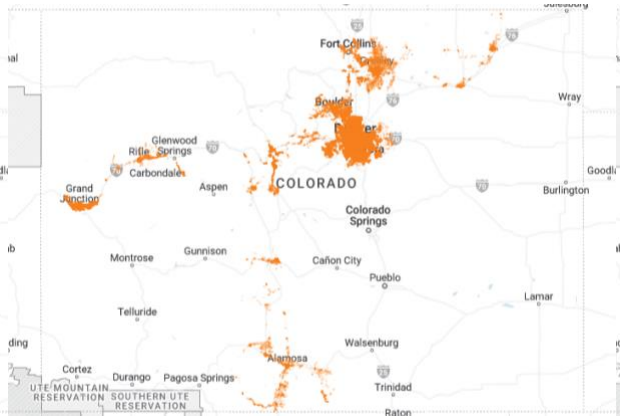
Figure K-7: HPWH adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 (Source: Kevala)

Scenario 2: Policy Aligned

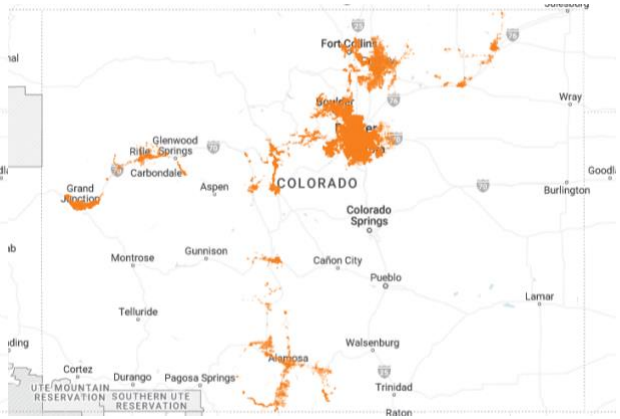
2025



2035

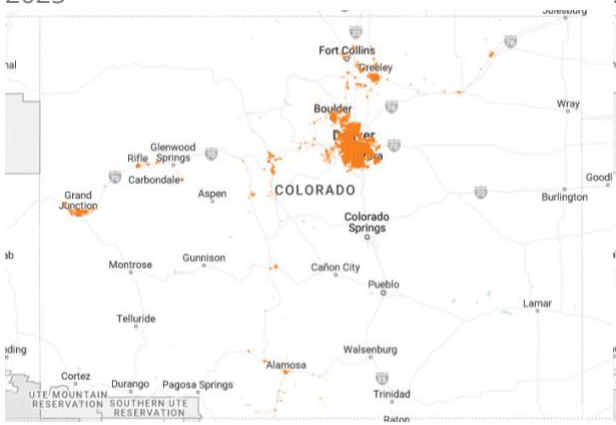


2045

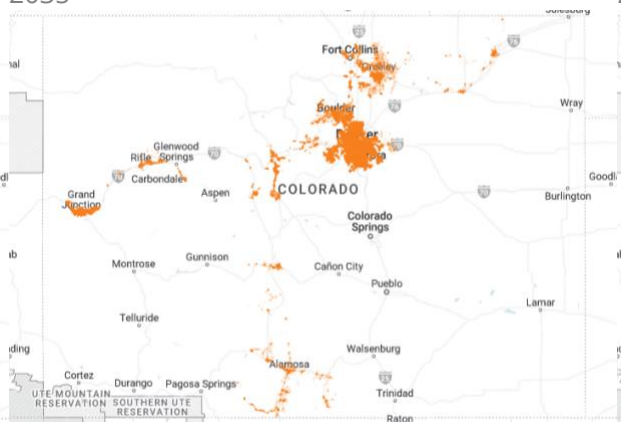


Scenario 3: Calibration

2025



2035



2045

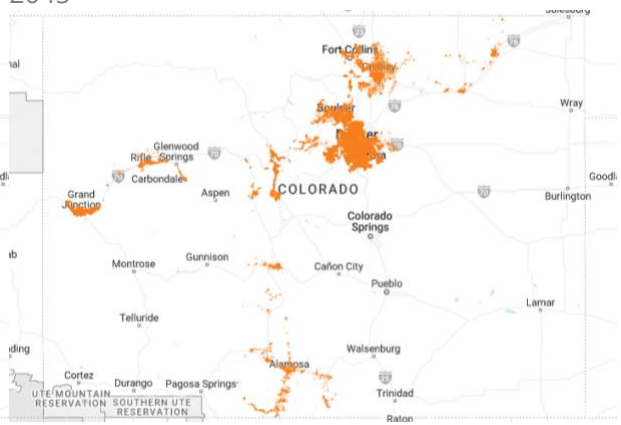


Figure K-8 and Figure K-9 are box and whisker charts showing the distribution of the contribution of HPWH to the feeder coincident peak and noncoincident peaks, respectively. The x-axis shows the study year while the y-axis shows the range of capacity contribution (kW) of the DER to system peak load. These charts show that HPWH are contributing to system peak hour loads, particularly in the later years when the peaks are moving to winter mornings. Similar trends are seen in the feeder non-coincident peaks.

Figure K-8: Distribution of HPWH at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala)



Figure K-9: Distribution of HPWH at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

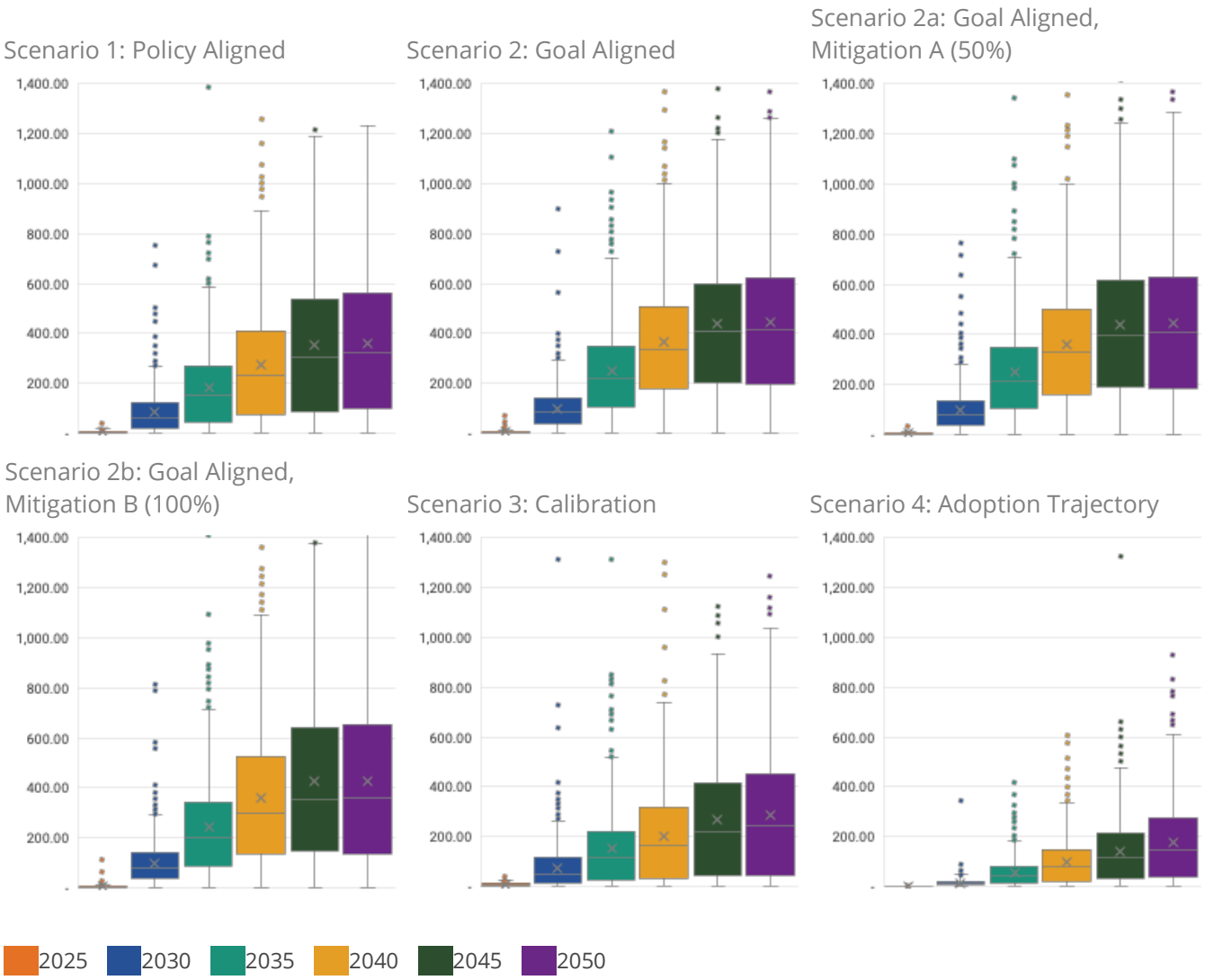
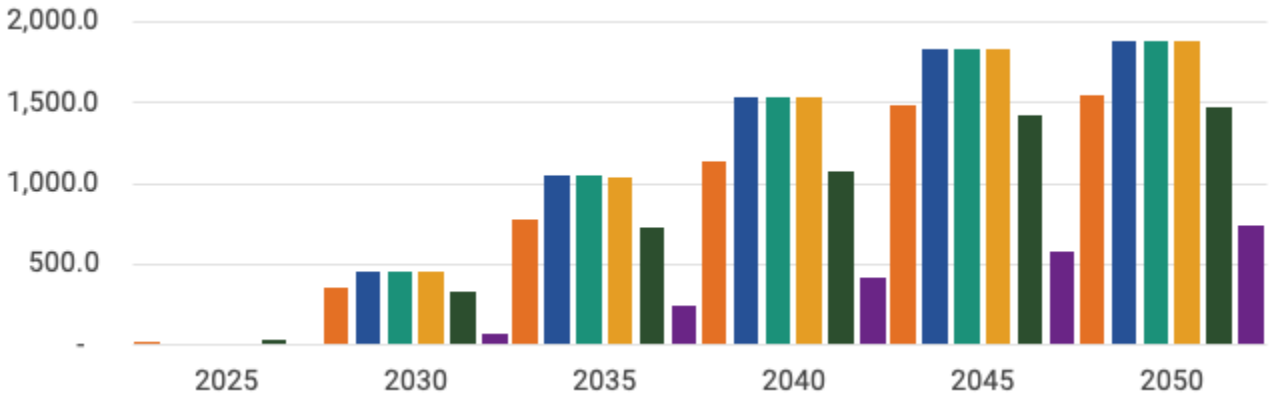


Figure K-10 shows the cumulative energy from HPWH for selected years by scenario. This chart shows significant growth from virtually zero in all scenarios in 2025 to nearly 2,000 GWh by 2045.

Figure K-10: Cumulative energy (GWh) from HPWH by year and scenario: 2025-2050 (Source: Kevala)





The following are key findings from Kevala's analysis of the HPWH results:

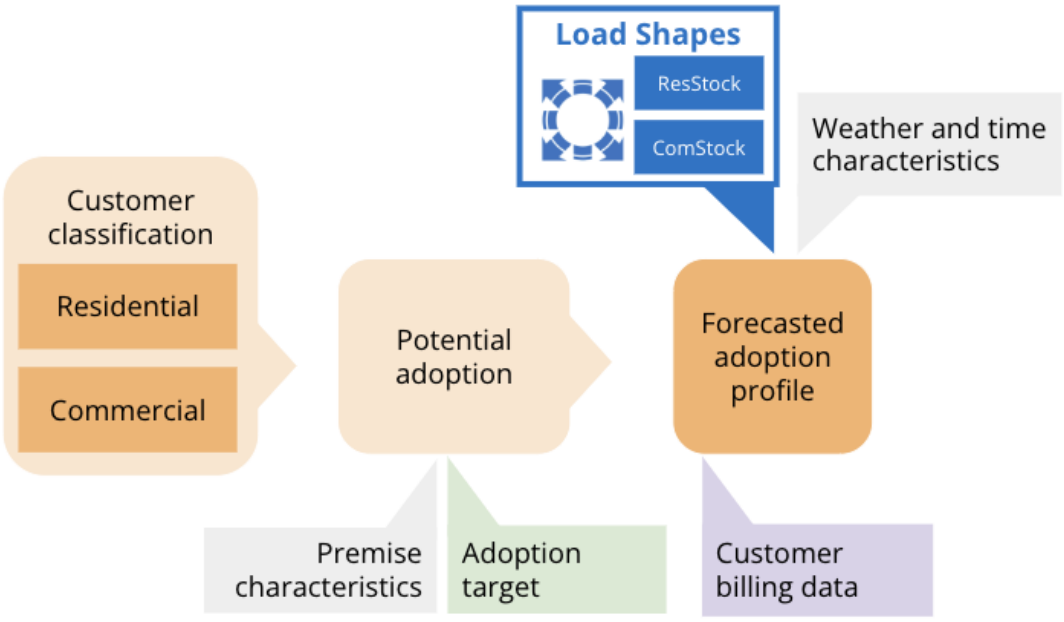
- HPWH generate load during morning hours; significant adoption levels will change the shape of feeder peaks.
- The acceleration of HPWH is gradual, providing time to address the growth of this technology.
- The HPWH load shape is also somewhat complimentary to personal EVSE, with low levels of load during late evening to early morning hours, which is a time period that managed personal EVSE loads tend to appear. Further, the load shape is complementary to solar PV, where HPWH load tends to be higher during times the solar PV systems are generating. Complementary strategies among HWPH, solar PV, and personal EVSE adoption could allow for better utilization factors for residential customers.

Appendix L. All-Electric Heat Pump Heating, Ventilation, and Air Conditioning Modeling Methodology and Additional Results

L.1 Approach

Kevala's heat pump heating, ventilation, and air conditioning (HP HVAC) methodology reflects a shift from fossil fuel-based air management systems relying to those powered by electricity, particularly furnaces that burn natural gas for heating degree days. Kevala's approach identified customers by sector, (i.e., residential and commercial), eligible to switch from gas-powered systems to HP HVAC systems and then estimated the size, behavior, and adoption for HP HVAC systems following the flow shown in Figure L-1. The HVAC systems modeled in this study combine a heat pump for heating and cooling and a backup electric resistance element for meeting peak heating needs. This technology was chosen based on input from PSCo as best representing its service territory. However, PSCo does expect significant adoption of heat pumps with backup gas heating. For this analysis, these configurations were not modeled because they are not expected to have as meaningful of electric system impacts as all-electric cold climate heat pumps.

Figure L-1: Flow diagram of HP HVAC modeling (Source: Kevala)



L.1.1 Sizing

Kevala matched a representative building from NREL's ResStock or ComStock datasets to each candidate premise.[65] Kevala selected the building in the premise's county with the total annual load closest to the premise's annual energy demand, derived from monthly electric bills provided by PSCo, and the same fuel usage type. If the county had less than 50 representative buildings of that customer revenue class and fuel usage type to choose from, a matching building from the larger statewide pool of buildings was chosen to better represent the building type.

To inform the representative building selection process, Kevala leveraged premise-specific gas usage data to determine the fuel usage type of each premise. Residential premises with both valid electric bills and natural gas bills were matched with ResStock buildings with natural gas usage. This resulted in approximately 1 million customers matched with ResStock buildings with natural gas usage, and approximately 350,000 customers matched with ResStock buildings with electric or propane space heating.

All commercial premises were assumed to have natural gas space heating and were only matched with buildings with natural gas space usage. This aligned with the PSCo-provided assumption that 96% of the commercial build stock in 2024 had gas space heating.

L.1.2 Behavior

For each premise, Kevala assigned and scaled the HP HVAC end-use profile of any given month based on the ratio between the estimated monthly load (from monthly electric bills) and the monthly load from the best-matched ResStock or ComStock profile. This scaled HP HVAC profile was then used to determine the relationship between HP HVAC load and weather and time-based features to forecast future HVAC activity at that location.

L.1.3 Adoption

After selecting a representative building type for each premise, premises were determined as eligible to adopt a HP HVAC if:

1. Revenue class was residential or commercial customer
2. If residential: had an associated gas bill or modeled heating fuel type that was not electricity at the start of the forecast

[65] NREL's ResStock and ComStock datasets model geographically specific building types with load profiles that account for local variations in water usage and heating technology types. To represent the HP HVAC end-use curves, Kevala used the 2022 1.1 ResStock's Upgrade 4 package, which specifically models the impact of upgrading from traditional HVAC to high efficiency HP HVAC with electric resistance backups.

3. If commercial: had a modeled heating fuel type that was not electricity at the start of the forecast and had a modeled HVAC technology type able to be upgraded to an HP rooftop unit or HP boiler.

If eligible for adoption, each premise received an adoption propensity score for its relative likelihood to adopt an HP HVAC in each year of the scenario.

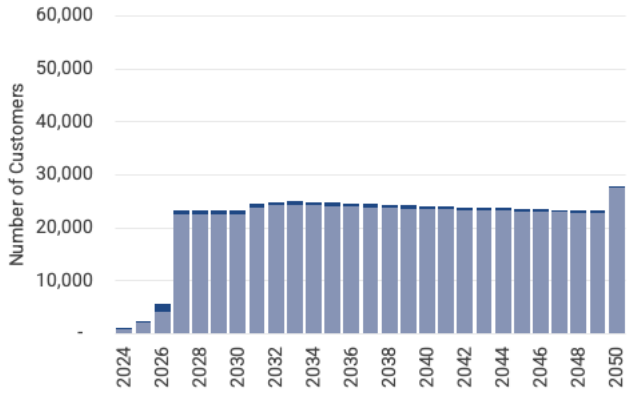
As with HPWH, because Boulder and Denver have strong policies for electrified heating in existing and new-build premises,[66] adoption scores were adjusted accordingly. For example, if a premise was both a new build and located within these cities, its propensity to adopt was, on average, four times as likely to adopt an HP HVAC as an existing building outside of Boulder or Denver.

Once adoption propensity scores were assigned for all eligible premises, Kevala ranked the eligible premises according to their score value and simulated adoption for each year in the forecast. Each year, adopting premises were selected one at a time from all eligible premises that had not already adopted HP HVAC until the service territory's top-down yearly target capacity was reached.

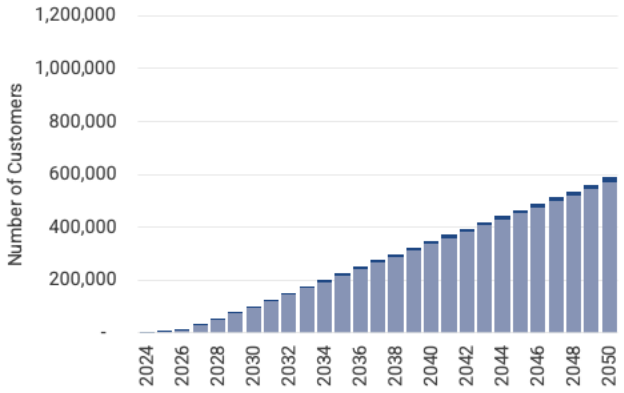
Figure L-2 shows the annual and cumulative HP HVAC targets used for this study by scenario. PSCo provided targets broken out between the residential and commercial customer classes. These targets were the number of customers switching from gas space heating (natural gas or propane) to HP HVAC. Customers with existing electric resistance space heating who switch to HP HVAC were accounted for within the EE targets (see Appendix H).

Figure L-2: Annual HP HVAC target adoptions by class, scenario, and year: 2024-2050 (Sources: PSCo, Kevala)

Scenario 1: Policy Aligned - Incremental

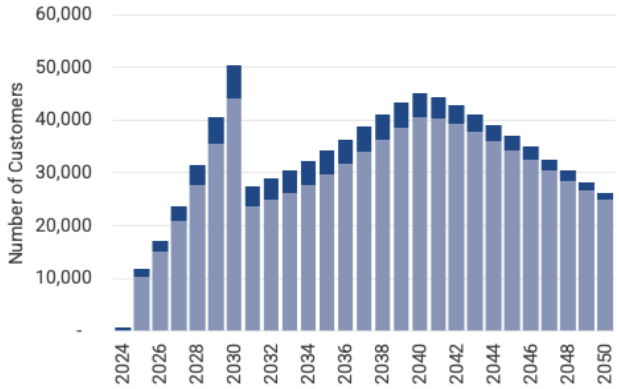


Scenario 1: Policy Aligned - Cumulative

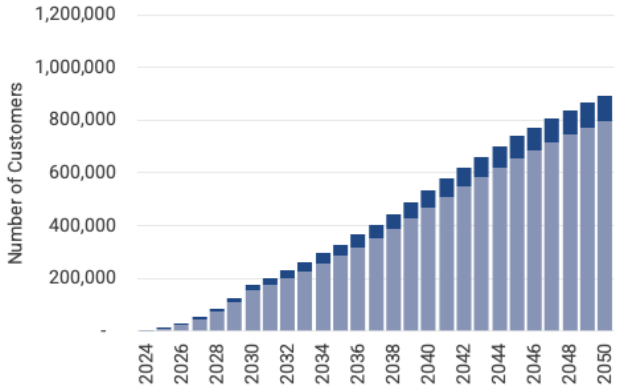


[66] For more information on these policies and mandates, see: Denver Council Bill 21-1310 and the City of Boulder 2024 Energy Conservation Code Update.

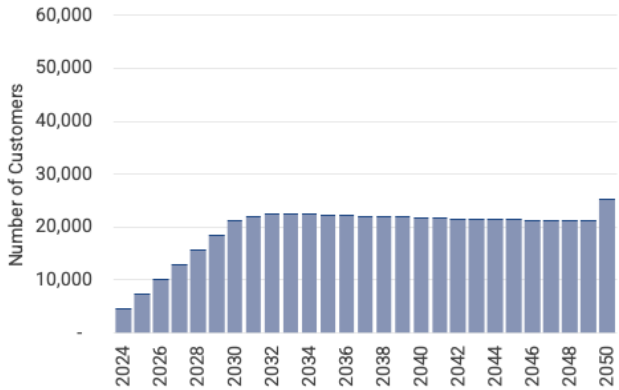
Scenario 2: Goal Aligned - Incremental



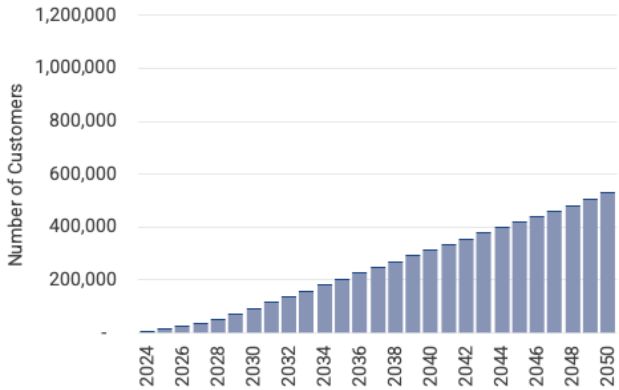
Scenario 2: Goal Aligned - Cumulative



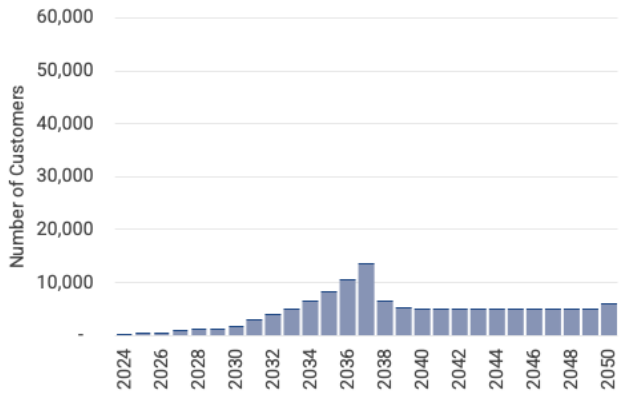
Scenario 3: Calibration - Incremental



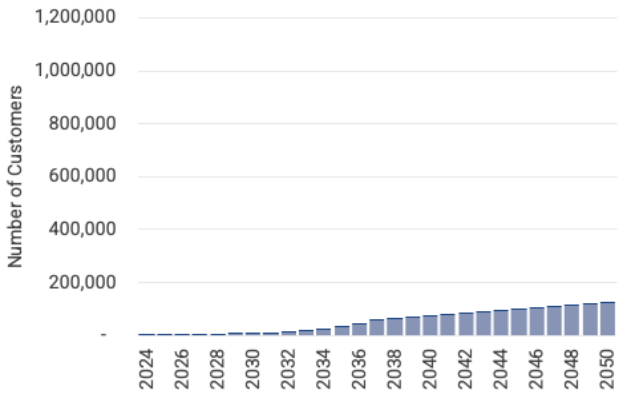
Scenario 3: Calibration - Cumulative



Scenario 4: Adoption Trajectory - Incremental



Scenario 4: Adoption Trajectory - Cumulative



Residential Commercial

The following are key assumptions associated with Kevala's HP HVAC modeling:

- Kevala's approach models the heating cycle of heat pumps only.
- Because the majority of PSCo customers have electrified cooling systems and the efficiency and load profiles of air conditioning and heat pump cooling cycles can be similar, Kevala

did not model cooling cycles and kept cooling loads as part of the existing base load to avoid double counting.

L.2 Analysis and Results

Figure L-3 shows the incremental and cumulative HPWH adoptions by class, scenario, and year. These adoptions track with the targets shown in Figure L-2.

Figure L-3: Annual HP HVAC adoptions by class, scenario, and year: 2024-2050 (Source: Kevala)

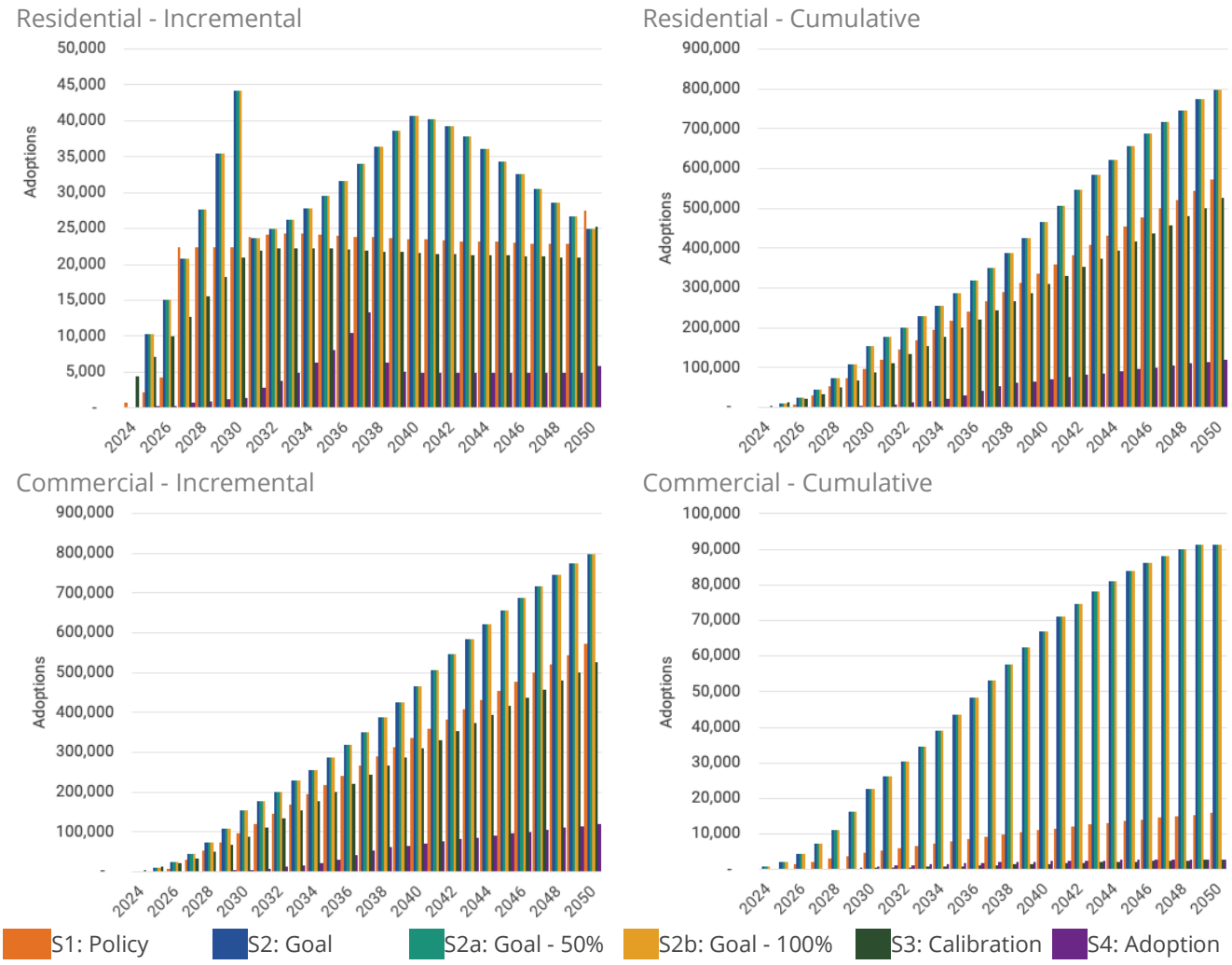


Figure L-4 and Figure L-5 show the distribution of adoptions on feeders by class, scenario, and year in a series of box and whisker charts (see Figure F-6 and the accompanying text for more detail on this type of chart). The x-axis shows the study year while the y-axis shows the range of the number of HPWH adoptions. The distributions of adoptions for residential and commercial are consistent with the shape of the adoption targets.

Figure L-4: Distribution of residential HP HVAC adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)

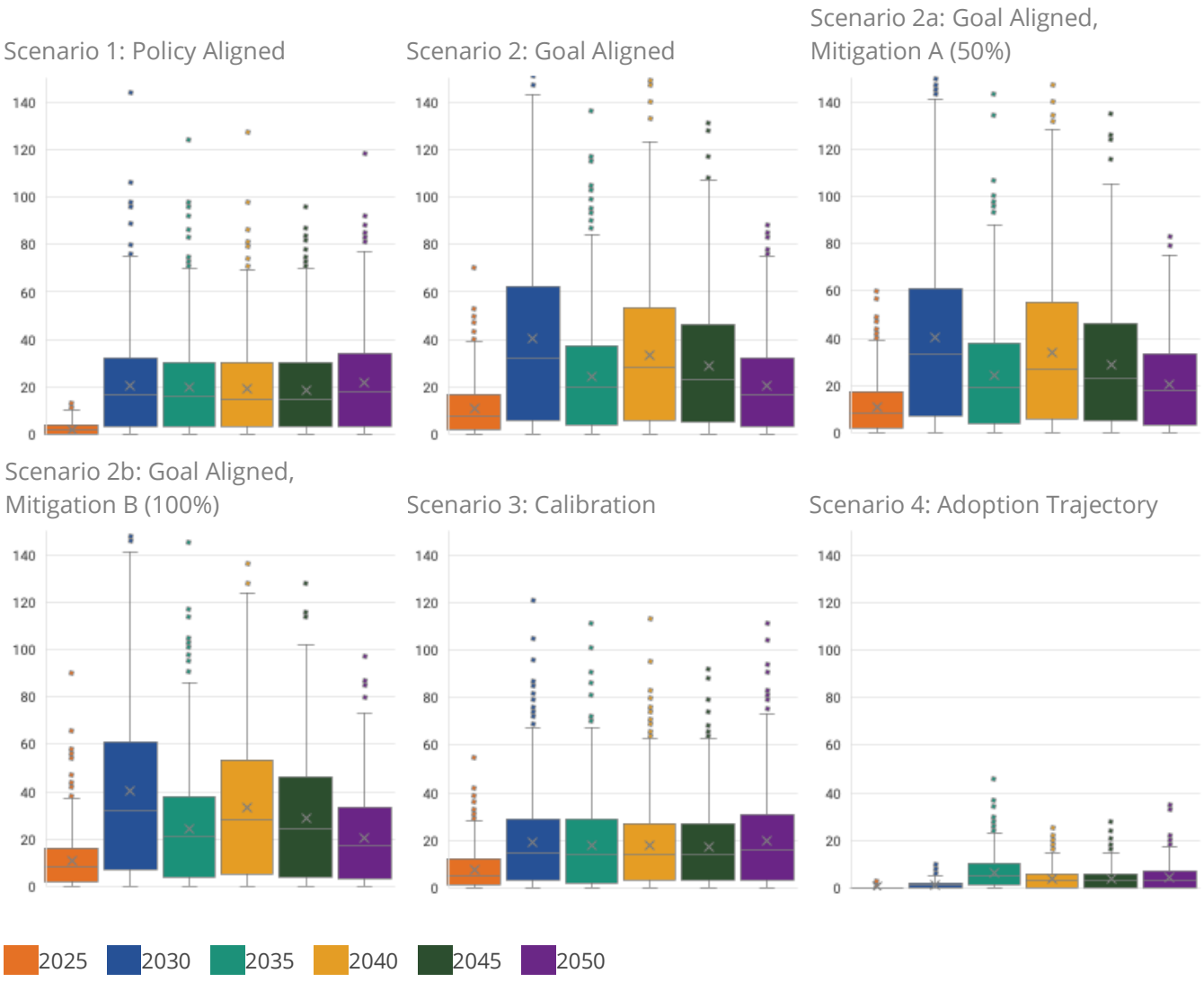


Figure L-5: Distribution of commercial HP HVAC adoptions per feeder by scenario and year: 2025-2050 (Source: Kevala)



The HP HVAC average load shapes for all the scenarios are shown in Figure L-6. These charts show the expected average load behavior from HP HVAC, and the differences among the scenarios over the years. These shapes represent a typical load shape for heating load, with a peak in the morning hours and smaller peak again in the early evening. Note these charts are showing average HP HVAC load at the premise and do not include losses.

Figure L-6: HP HVAC average load shape by scenario and year (kWh): 2025-2050 (Source: Kevala)

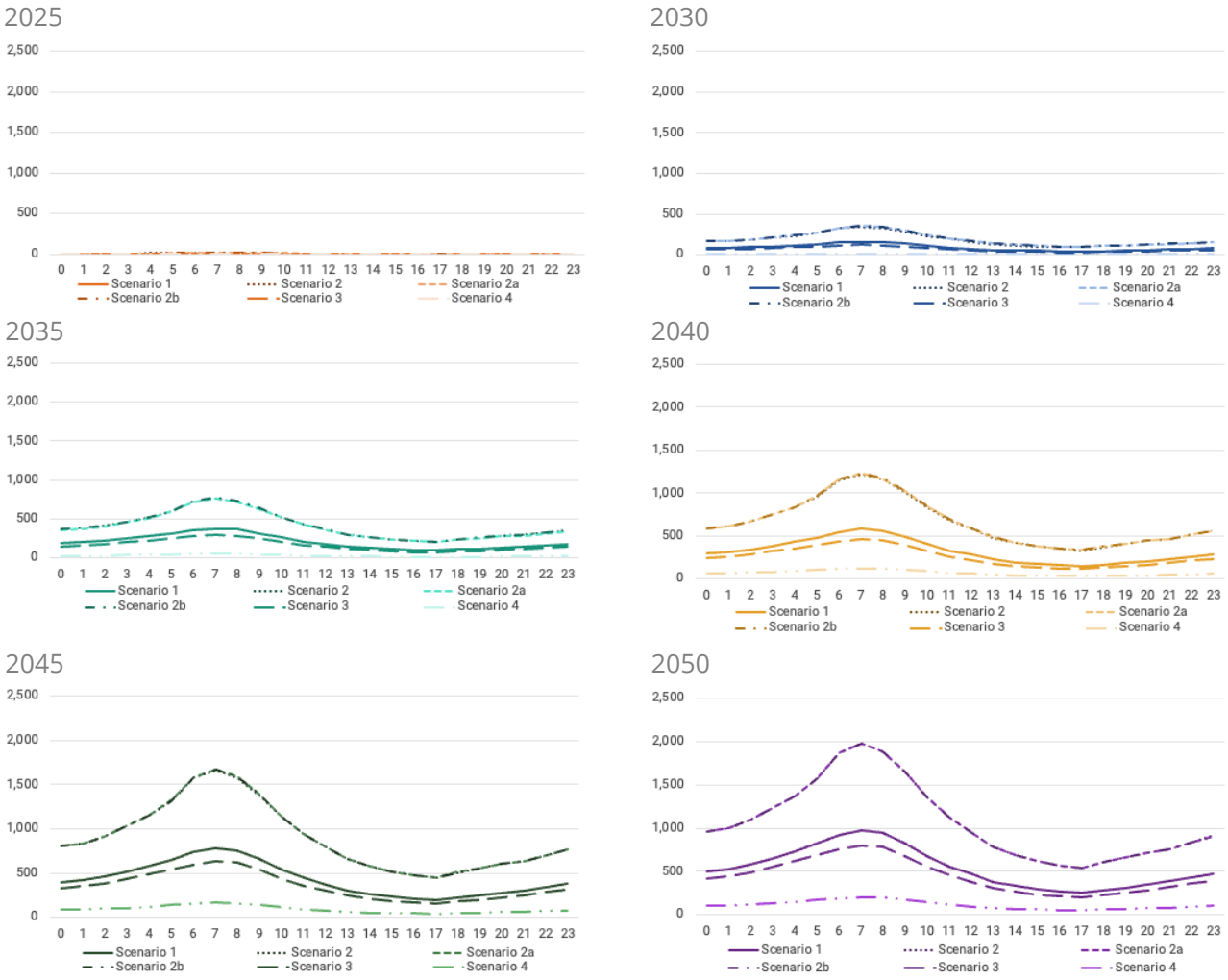
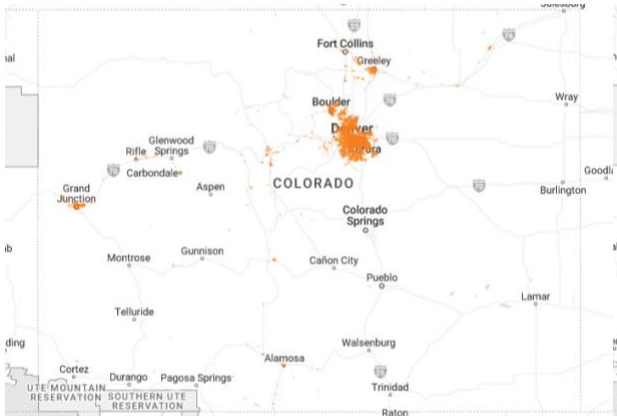


Figure L-7 shows the adoptions geographically. As these diagrams show, the adoptions early on (2025) are concentrated in the metropolitan areas where there are more significant concentrations of residential customers. Over time, other areas see more adoption concentrated in urban and suburban areas as well as outlying areas.

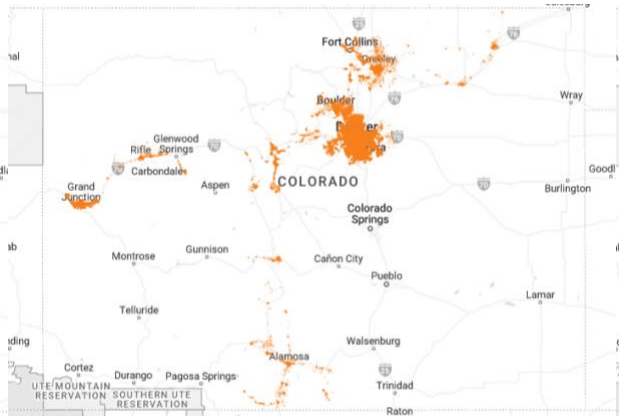
Figure L-7: HP HVAC adoption across PSCo service territory, Scenario 2 (Policy Aligned) and Scenario 3 (Calibration): 2025-2045 (Source: Kevala)

Scenario 2: Policy Aligned

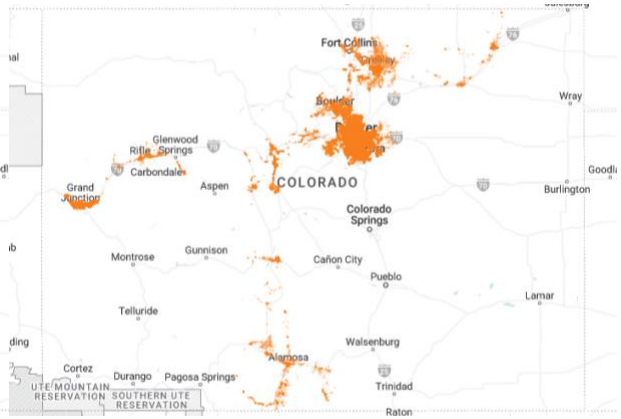
2025



2035

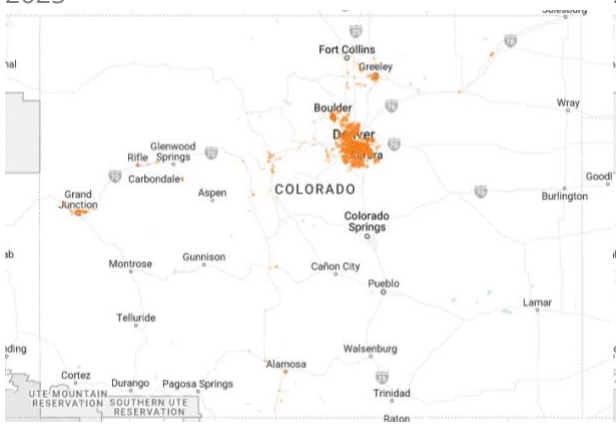


2045

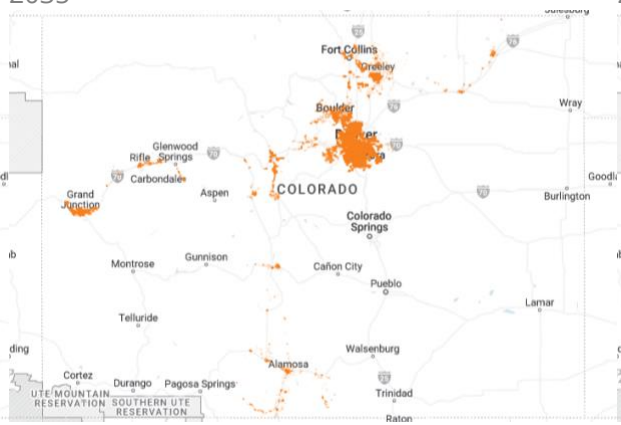


Scenario 3: Calibration

2025



2035



2045

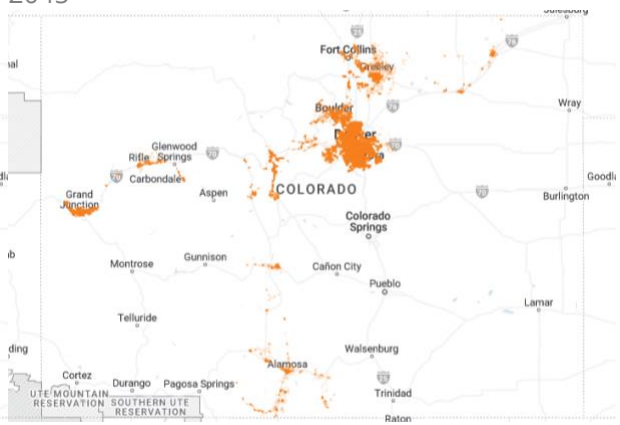


Figure L-8 and Figure L-9 are box and whisker charts showing the distribution of the contribution of HP HVAC to the feeder coincident peak and noncoincident peaks, respectively. The x-axis shows the study year while the y-axis shows the range of capacity contribution (kW) of the DER to system peak load. These charts show that HP HVAC is contributing to peak hour loads, particularly in the later years when the peaks are moving to winter mornings. A similar trend is seen in the feeder non-coincident peaks. For all but the Adoption Trajectory Scenario, the distribution grows wider over time with more and more outliers in the later years. This is driven by the diversity of feeder premises, with those feeders with more residential than average increasing loads due to the HP HVAC loads.

Figure L-8: Distribution of HP HVAC at the system peak (kW) by year and scenario: 2025-2050 (Source: Kevala)



Figure L-9: Distribution of HP HVAC at the feeder peak (kW) by year and scenario: 2025-2050 (Source: Kevala)

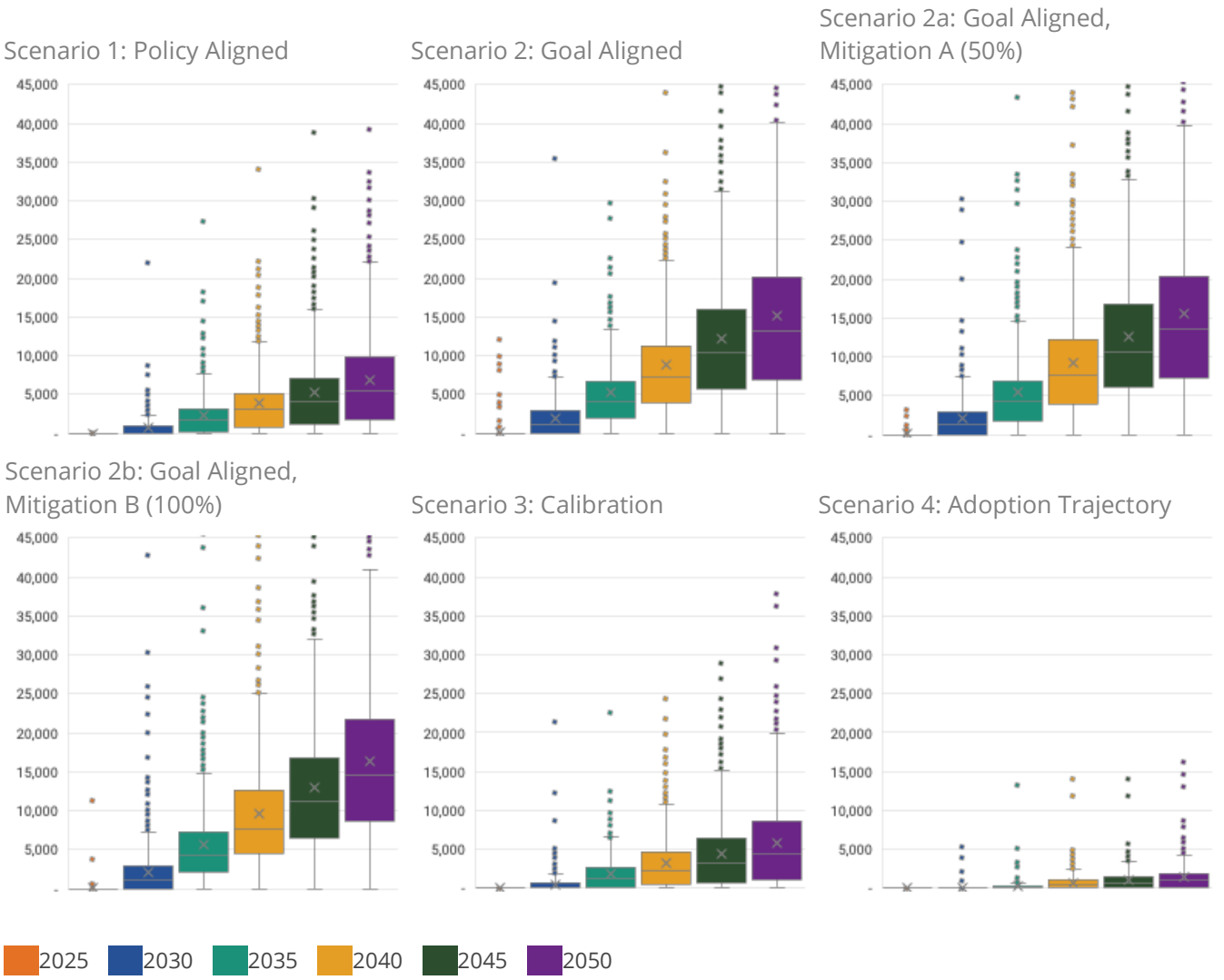
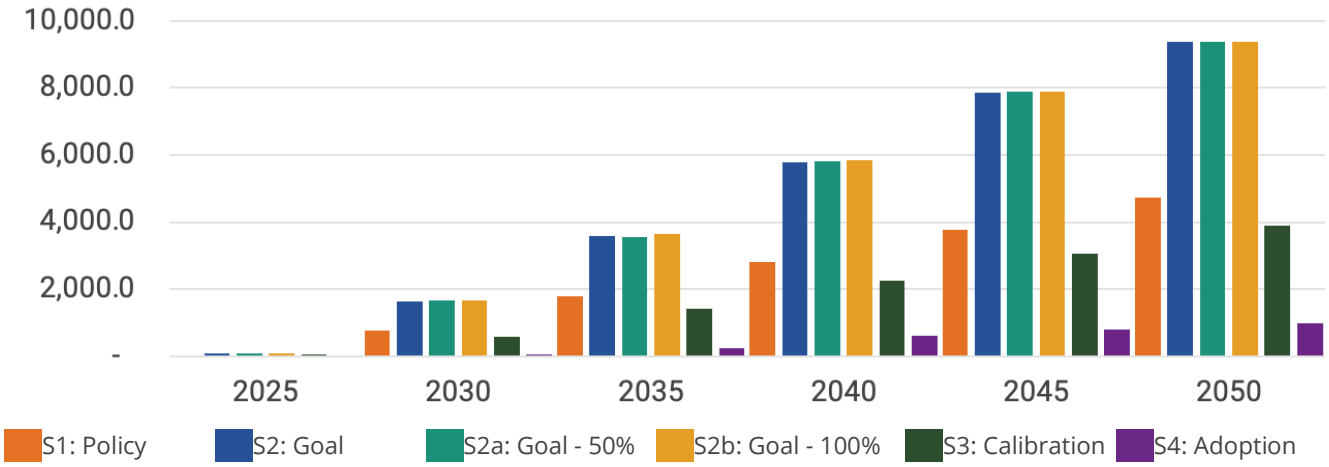


Figure L-10 shows the cumulative energy from HP HVAC for selected years by scenario.

Figure L-10: Cumulative energy (GWh) from HP HVAC by year and scenario: 2025-2050 (Source: Kevala)



The following are key findings from Kevala's analysis of the HP HVAC results:

- HP HVAC, like HPWH, is increasing steadily over the forecast period and is contributing to the shift to morning peaks.
- Coordination among solar PV, EVSE, and HP HVAC adoptions could benefit distribution planning as customers could be incented to manage their energy use to improve utilization and flatten loads rather than adding to peak loads.



Appendix 2 - NWA CBA

Cost-Benefit Analysis of Non-Wires Alternatives

Public Service Company of Colorado

December 9, 2024

Prepared by ICF for Public Service Company of Colorado

Xcel Energy®

ICF

Table of Contents

1 Executive Summary 2
1.1 Background and Purpose 2
1.2 Structure of the Report 2
2 Relevant Cost-Effectiveness Tests 3
2.1 Expanded, Modified Total Resource Cost Test 3
2.2 Utility Cost Test 4
2.3 Ratepayer Impact Measure 4
3 Methods for Quantifying Individual CBA Impacts 4
3.1 Impact Overview (Description, Inclusion) 4
3.2 Utility System Impacts 9
3.3 Distribution Service Area Customer Impacts 16
3.4 Lost Revenue and Rate Impacts 18
3.5 Host Customer Impacts 19
3.6 Societal Impacts 23
3.7 Other Fuel Impacts 26
4 Key Analysis Assumptions 27
4.1 Accounting Assumptions 27
4.2 Discount Rates 27
4.3 System Risk Relief Requirement 28
4.4 System Risk Relief Provided 28
4.5 Monthly Peak Demand 28
4.6 System Peak Definition 29
5 Appendix 30
5.1 Non-Applicable Potential Utility System Impacts 30
5.2 Non-Applicable Potential Host Customer Impacts 32
5.3 Non-Applicable Potential Societal Impacts 32
5.4 Non-CBA Value Considerations 34

I Acronyms and Abbreviations

Acronyms and abbreviations are used throughout this report and are depicted here for ease of reference.

BESS	Battery Energy Storage System
CAIDI	Customer Average Interruption Duration Index
CBA	Cost-Benefit Analysis
CES	Clean Energy Standards
CMO	Customer Minutes Out
DER	Distributed Energy Resources
DG	Distribution Generation
DIC	Disproportionally Impacted Communities
DR	Demand Response
DSM	Demand-Side Management
DSP	Distribution System Plan
ECT	Electric Continuity Threshold
EE	Energy Efficiency
EM&V	Evaluation, Measurement, and Verification
EMTRC	Expanded, Modified Total Resource Cost [test]
ERP	Electric Resource Plan
GHG	Greenhouse Gas
IE	Included Explicitly
II	Included Implicitly
JST	Jurisdiction-Specific Test
kW	Kilowatt
kWh	Kilowatt-hour
MTRC	Modified Total Resource Cost test
NA	Not Applicable
NEI	Non-Energy Impact
NREL	National Renewable Energy Laboratory
NSPM	National Standard Practice Manual [for Benefit-Cost Analysis of DERs]
NWA	Non-Wires Alternatives
O&M	Operations and Maintenance
PIM	Performance Incentive Mechanism
PV	Photovoltaic
REopt	Renewable Energy Integration and Optimization [tool from NREL]
RIM	Ratepayer Impact Measure
RPS	Renewable Portfolio Standard
SAIDI	System Average Interruption Duration Index
SCC	Social Cost of Carbon
SRRP	System Risk Relief Provided
SRRR	System Risk Relief Required
TMY3	Typical Meteorological Year
U.S. DOE	United States Department of Energy
UCT	Utility Cost Test
VoLL	Value of Lost Load

1 Executive Summary

1.1 Background and Purpose

On October 26, 2021, the Colorado Public Utilities Commission ("CPUC") finalized Distribution System Planning rules applicable to Qualifying Retail Utilities ("QRUs") in Proceeding No. 20R-0516E. These rules took effect on January 14, 2022 and require Public Service Company of Colorado ("Public Service" or "the Company") to file a Distribution System Plan ("DSP") every two years. Part of these rules require Public Service consider Non-Wires Alternatives (NWAs) for Major Distribution Grid Project ("MDGPs"). The Commission defined the following criteria for determining NWA suitability:

1) The project should occur during the 10-year planning horizon;
2) The system constraint must be due to thermal loading, voltage, capacity or reliability issues and could be resolved by a Distributed Energy Resource (DER), a reduction in peak demand loading, a reduction in energy consumption, or load shifting on the transmission or distribution facilities; and
3) The conventional solution should still be within the planning or design stage, with no major equipment on order, received, or installed that cannot be repurposed for other uses.

For MDGPs that pass the initial NWA suitability screening, the Commission Rules require Public Service to conduct a technology-neutral competitive solicitation to consider proposals that may defer the traditional utility infrastructure investment. As a part of the competitive solicitation process, the Commission rules require Public Service to develop a methodology for evaluating the cost-effectiveness of proposed NWA projects that considers the principles outlined by the National Standard Practice Manual[1] (NSPM). Public Service contracted ICF, a co-author of the NSPM, to assist in creating a viable methodology for evaluating the cost-effectiveness of NWAs.

The methodology detailed in this report is intended to be used to evaluate NWA costs and benefits compared to those of a traditional utility infrastructure solution. This analysis should be conducted after Public Service has performed an initial suitability screening to assess the risks associated with deferring the distribution project. This suitability screening must determine that a potential NWA would not compromise the safety or reliability of the grid in Public Service's territory, after which the methods detailed in this report will be used to assess the costs and benefits of the proposed NWAs as compared to the traditional infrastructure solution.

1.2 Structure of the Report

The following report is structured to cover the core components of the Company's proposed NWA Cost-Benefit Analysis (CBA) methodology including:

- Relevant Cost-Effectiveness Tests,
- Methods for Quantifying Individual CBA Impacts, and
- Key Analysis Assumptions.

[1] National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. August 2020. https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

The "Relevant Cost-Effectiveness Tests" section discusses the three cost-effectiveness tests that the Company proposes to holistically evaluate the benefits and costs of a proposed NWA project. The three tests include the Expanded, Modified Total Resource Cost Test (EMTRC) which considers the principles of the NSPM[2], in addition to the well-established Utility Cost Test (UCT), and Rate Impact Measure (RIM) test. The section describes the tests and their methodological considerations at a high-level; providing initial context for the types of impacts that may or may not be considered within each test.

In the "Methods for Quantifying Individual CBA Impacts" section, a detailed explanation on each potential CBA impact (also referred to throughout this document as "value stream") and the impact's representation (or lack thereof) within the three specific cost tests. Each outlined value stream includes a description of the impact, cost-effectiveness tests the impact will be included in, relevant equations, data, and assumptions for quantification (if applicable), as well as any additional considerations surrounding impact inclusion or quantification. This section contains a majority of the content in this report.

The final section, "Key Analysis Assumptions," describes NWA CBA assumptions that will significantly affect the calculation of one or more value streams within the CBA. The discussed assumptions include discount rates, system relief requirements, and peak load definition. Details include justification for the selected values or methods for quantification, and/or information on how specific values will be calculated.

2 Relevant Cost-Effectiveness Tests

2.1 Expanded, Modified Total Resource Cost Test

The NSPM advocates that cost-effectiveness testing should be performed using a Jurisdiction-Specific Test (JST), a cost-effectiveness test that takes the "regulatory perspective." The regulatory perspective is the perspective of the entity overseeing utility investment decisions, such as a public utilities commission. A JST should reflect applicable policy goals of a jurisdiction and should include all utility system impacts in addition to those impacts that align with jurisdiction policy goals. These can include societal impacts as well as host customer impacts, depending on the jurisdictional policies.[3] Since a JST is intended to reflect jurisdiction-specific needs, requirements, and goals, there is no single, "off-the-shelf" JST.

In its existing CBA framework for the evaluation of its Demand-Side Management ("DSM") programs, Public Service utilizes a Modified Total Resource Cost ("MTRC") test. While a Total Resource Cost ("TRC") test as defined by the California Standard Practice Manual[4] usually includes host customer and utility system benefits, the scope of the Public Service's MTRC has been broadened to include Greenhouse Gas (GHG) impacts, which is a societal value stream. Note that the MTRC also includes a value stream for host customer Non-Energy Impacts ("NEIs") through a "Non-Energy Benefits Adder." Even though it is not explicitly stated, Public Service's MTRC already incorporates a regulatory perspective, as it broadens the scope of the TRC test to account for jurisdictional policy goals, in this case the consideration of GHG impacts and other potential benefits through the Non-Energy Benefits Adder. Pursuant to CPUC Rule 3535, Public Service has incorporated considerations from the NSPM's JST that build on the foundation of the MTRC, incorporating

[2] Further explained in section 2.1 Expanded, Modified Total Resource Cost Test.
[3] National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. August 2020. https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/
[4] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects. October 2001. cpuc-standard-practice-manual.pdf (ca.gov)

additional value streams to reflect localized and customer benefits that may be realized by NWAs. Because the formulated test expands upon Public Service's existing MTRC test (which already encapsulates many JST value streams), Public Service is referring to the test as the "Expanded, Modified TRC" (EMTRC).

In alignment with the principles of the NSPM, the EMTRC accounts for applicable policy goals in Public Service's territory including, but not limited to, clean energy and equity goals.

2.2 Utility Cost Test

The Utility Cost Test is used to evaluate the cost-effectiveness of a NWA project from the viewpoint of the Company on a utility resource basis, meaning that customer rate impacts are not included. The purpose of including this test in the methodology is to answer the question of whether an NWA will help Public Service to lower the cost of delivering electricity to its customers. Therefore, the UCT includes all utility system value streams, including both direct impacts to the distribution system (for which an NWA is intended) as well as the impacts that DERs have on the broader utility system. This allows for a complete picture of the impact of the DER from the utility system perspective. The UCT does not include any societal or host customer value streams, as they are not relevant in this case.

2.3 Ratepayer Impact Measure

The Ratepayer Impact Measure test evaluates the effect of an NWA solution on customer electricity rates due to changes in utility costs and revenues.

In considering the NSPM principles, rate impacts should not be included in a JST, and therefore are not included in the EMTRC. However, the RIM test is included as part of the NWA CBA methodology as it provides a distinct and important perspective of how the NWA will directly impact customer rates, which is a separate question from whether or not the NWA is cost-effective when factoring in broader customer, societal, and utility costs and benefits. Notably, an NWA can "pass" a JST and/or EMTRC and still raise customer rates as demonstrated through a RIM test. This provides an additional viewpoint from which the merit of the NWA can be evaluated by both Public Service and the Commission.

3 Methods for Quantifying Individual CBA Impacts

3.1 Impact Overview (Description, Inclusion)

The NSPM outlines over 30 potential CBA impacts for inclusion within cost-effectiveness tests. The potential impacts span utility system, host customer, and societal benefits and costs. Public Service has considered the inclusion of each of these value streams in addition to value streams with specific relevance to their system. The following section outlines how each potential value stream has been treated in the cost-effectiveness tests considered by Public Service for CBA of NWAs (EMTRC, UCT and RIM). This includes which tests each value stream has been included in, as well as how the value stream will be quantified.

For the UCT and RIM test, the inclusion and exclusion of different value streams follows the well-established definitions for each of these tests as outlined in the California Standard Practice Manual, cpuc-standard-practice-manual.pdf. The UCT considers all utility system impacts, and the RIM considers these as well as utility revenue impacts. In considering the

principles of the NSPM, the EMTRC includes all utility system impacts, as well as the host customer and societal impacts which are deemed relevant based on Public Service's policy landscape.

Table 1 depicts the potential value streams and their inclusion status within each NWA cost-effectiveness test. Inclusion of these value streams if further defined by the following definitions:

- **IE = Included Explicitly:** Value stream is included as a standalone calculation or input within the methodology.
- **II = Included Implicitly:** Value stream is included but is represented as a subcomponent of another value stream due to the nature of available data.
- **NA = Not Applicable:** Value stream is not applicable to the test. For UCT and RIM this is based on the well-established perspectives of each of these tests. In the case of the EMTRC, the value stream is not applicable based on Public Service's policy landscape. For all three tests, a value stream may also be excluded if it is projected that the impact is de minimis or there is a lack of defensible methods for quantification. Finally, a value stream may also be not applicable for the EMTRC despite policy goals due to concerns of double counting impacts, as is the case for Economic and Jobs impacts.

Table 1: Potential CBA Impacts and Inclusion within Public Service NWA CBA Tests

	Impact	Description[5]	EM TRC	UCT	RIM
Utility System Impacts	Energy Generation	The cost of production or procurement of energy ($/kWh) from bulk scale generation resources on behalf of customers	IE	IE	IE
	Generation Capacity	The cost of generation capacity ($/kW) required to meet the forecasted system peak load net of renewable generation or "net demand."	IE	IE	IE
	Environmental Compliance	Costs to comply with environmental regulations	II	II	II
	RPS/CES Compliance	Costs to comply with renewable portfolio standards or clean energy standards	NA	NA	NA
	Wholesale Market Price Effects	The decrease (or increase) in wholesale market prices because of reduced (or increased) customer consumption	NA	NA	NA
	Ancillary Services	Services required to maintain electric grid stability and power quality	NA	NA	NA
	Transmission Capacity	Cost associated with ensuring the availability of the transmission system to transport electricity safely and reliably	NA	NA	NA

[5] National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources Summary, August 2020. https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-Summary_08-24-2020.pdf

Impact		Description[5]	EM TRC	UCT	RIM
	Transmission System Losses	Electricity or gas lost through the transmission system	II	II	II
	Distribution Capacity	Costs associated with ensuring the availability of the distribution system to transport electricity or gas safely and reliably	IE	IE	IE
	Distribution System Losses	Electricity lost during transit through the distribution system	II	II	II
	Distribution O&M	Costs associated with operating and maintaining the distribution system	IE	IE	IE
	Distribution Voltage	Maintaining voltage levels within an acceptable range	NA	NA	NA
	Financial Incentives	Financial incentives provided to DER host customers to encourage DER implementation	NA	IE	IE
	Program Administration	Administration and management costs of the NWA project/program	IE	IE	IE
	Utility Performance Incentives	Incentives offered to utilities to encourage successful, effective implementation of NWA projects/programs	IE	IE	IE
	Credit and Collection	Costs associated with bad debt, customer disconnections, reconnections	NA	NA	NA
	Risk	Uncertainty including operational, technology, cybersecurity, financial, legal, reputational, and regulatory risks	II	II	II
	Reliability	Maintaining generation, transmission, and the distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components	NA	NA	NA
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions	NA	NA	NA
Distribution Service	Reliability	The benefit provided by new utility infrastructure solutions to reduce the likelihood of equipment failure resulting customer outages[6]	IE	NA	NA

[6] Note: This would only apply to reinforcing or upgrading existing infrastructure vs. constructing a new feeder or substation

Impact		Description[5]	EM TRC	UCT	RIM
	Economic Development	Headroom created by traditional utility investments which can allow new customer loads to be expediently, and cost effectively connected to the distribution system	NA	NA	NA
Lost Revenue and Rate Impacts	Utility Lost Revenue/Customer Bill Savings	Reductions in customer energy sales from DER that result in lost revenue for the utility and bill savings for the customer	NA	NA	IE
Host Customer Impacts	DER Hosting Capacity	The ability of a traditional infrastructure solution to increase DER hosting capacity on the distribution system and therefore may reduce the need for separate upgrades which would be paid for by the interconnection customer.	NA	NA	NA
	Host Portion of DER Costs	Costs incurred to install and operate DERs	IE	NA	NA
	Host Transaction Costs	Other costs incurred to install and operate DERs	NA	NA	NA
	Interconnection Fees	Costs paid by the host customer to the utility to interconnect DERs to the distribution system	IE	IE	IE
	Risk	Uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error	NA	NA	NA
	Reliability	The ability to prevent or reduce the duration of host customer outages	IE	NA	NA
	Resilience	The ability to anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from disruptions	NA	NA	NA
	Tax Incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs	NA	NA	NA
	Host Customer NEIs	Benefits and costs of DERs that are separate from energy-related impacts	IE	NA	NA
	Income-qualified and DIC NEIs	Non-energy benefits and costs that affect income-qualified DER host customers	IE	NA	NA
Societal	Resilience	Resilience impacts beyond those experienced by utilities or host customers	NA	NA	NA

Impact		Description[5]	EM TRC	UCT	RIM
	GHG Emissions, CO_2	CO_2 impacts from fossil-fueled resources	IE	NA	NA
	GHG Emissions, Methane	Methane impacts from fossil-fueled resources	IE	NA	NA
	Other Environmental	Other air emissions, solid waste, land, water, and other environmental impacts	NA	NA	NA
	Economic and Jobs	Incremental economic development and job impacts	NA	NA	NA
	Public Health	Health, medical costs, and productivity impacts	IE	NA	NA
	Low Income: Society	Poverty alleviation, environmental justice, and reduced home foreclosures	NA	NA	NA
	Energy Security	Energy imports and energy independence	NA	NA	NA
Other Fuel System Impacts	Natural Gas Supply Cost	Avoided gas costs from DSM measures such as weatherization	IE	NA	NA

In sections 3.2 Utility System Impacts, 3.5 Host Customer Impacts, and 3.6 Societal Impacts, each potential CBA impact is discussed with a detailed description of the impact and associated information on CBA inclusion and/or calculation methods. Each impact title is labeled with one of the following:

- Explicitly Included, Calculated
- Implicitly Included, Calculated
- Explicitly Included, Input
- Not Applicable

The initial term in each label (explicitly included or implicitly included), denotes how each impact will be included within the CBA tests. If an impact is designated as included, it means that the impact will be included in at least one of the three CBA tests. The test(s) that the impact is included in are listed in the description of the impact (the same information shown in

Table 1). "Explicitly included" means that the impact will be included as its own distinct value stream. "Implicitly Included" means that the impact has been implicitly included in another value stream, and so does not constitute a separate value stream that is calculated on its own. This could occur in cases where the value stream is a calculation input for another impact (e.g., distribution system losses are an input in the distribution capacity impact calculation), or when two values cannot easily be disaggregated from their original bundled value (e.g., environmental compliance costs included in energy generation costs).

The second term in each label (calculated or input), indicates whether the value stream is calculated within the methodology, or if the value steam is to be calculated prior to the application of the methodology and be

an open input applied on a project-specific basis in the NWA CBA model. Impacts designated as an "input" are provided by either the NWA project bidder or Public Service, and the responsible party is designated in the description of each impact.

Value streams labeled "Not Applicable" will not be included in the NWA CBA calculation, either implicitly or explicitly, in any of the three CBA tests being conducted for NWA.

3.2 Utility System Impacts

3.2.1 Energy Generation: Explicitly Included, Calculated

Energy Generation Cost Impacts are due to a utility's reduced need to produce or procure electricity on behalf of their customers. In the context of an NWA, DERs will more commonly create a net benefit in this value stream through customer-sited generation or load reduction. In these cases, this impact can also be referred to as "Avoided Energy Generation." The value of this impact includes both direct costs avoided by not having to produce or procure the energy (such as avoided fuel costs) as well as indirect costs such as compliance with environmental regulations (such as the costs for equipment added to thermal plants to comply with Clean Air Act standards). One important consideration to note on the environmental compliance front is that since the avoided energy cost data is sourced from the 2024 Vision Plan. The Vision plan is a result of Xcel's Public Service's Electric Resource Plan (ERP). The cost of complying with Colorado's GHG emissions reductions goals is already internalized in this value stream.[7]

3.2.1.1 Calculation Responsibility and Test Inclusion

Energy generation cost impacts will be calculated within Public Service's NWA CBA methodology using the equation and data inputs outlined below. This value stream is from the utility system perspective and will be included in the EMTRC, UCT, and RIM tests.

3.2.1.2 Impact Equation and Variables

$$Avoided\ Energy\ Generation\ _y = \sum_{h=1}^{8760} \frac{P_{y,h} * \Delta E_h}{1 - L_{ME(D \to G)}} \qquad Equation\ 1$$

Equation variables are defined as follows:

$\boldsymbol{y}$ is a subscript indicating that a variable is year-specific.

$\boldsymbol{h}$ is a subscript indicating that a variable should reflect hourly changes in value and should be determined using 8760 hourly data.

$\boldsymbol{P}$ ($/kWh) is the hourly avoided energy price. This value includes energy and environmental compliance costs since the values are not disaggregated in Public Service's current energy price data.

[7] Retrieved from Phase I & II of Public Service's Electric Resource Plan. Approved by the Public Utilities Commission in Proceeding 21A-0141E in 2022 and 2024, respectively.

ΔE (kWh) is the change in energy at the installation location of the DER during each hour that directly results from the implemented NWA and its associated measures.

$L_{ME(D \to G)}$ (%) is the utility's expected energy line loss factor from the location of the installed DER to the generator. Depending on the DER location, the parameter could account for transmission losses or transmission & distribution losses.

3.2.1.3 Data Source and Assumptions

Avoided Energy Prices (P): The avoided energy cost calculation will utilize hourly 8760 avoided energy prices from Public Service's 2024 Vision Plan. These model runs provide avoided energy price data in $/kWh for each hour of the year through 2050. Data will come from 2024 Vision Plan. These prices include the cost of "environmental compliance" for GHG regulations as the scenario exceeds Colorado GHG emissions reduction goals established through Clean Energy Plan filing requirements.

Change in Energy (ΔE): The NWA project bidder will provide one 8760 forecasted hourly measure load shape which is representative of the average performance of the DER during its lifetime. Measure load shapes should be forecasted using TMY3 weather data from 2017, in order to align weather conditions, holidays, and days of the week across CBA calculations

Line Loss Rates ($L_{ME(D \to G)}$): The calculation will utilize marginal energy line loss rates calculated from Public Service's most recent line loss study. Appropriate line loss rates (distribution vs. distribution and transmission) will be selected based on the location of the DER.

3.2.1.4 General Considerations

The use of an hourly avoided energy load shape to determine change in energy due to a DER will provide increased accuracy compared to traditional impact valuation methods, which typically utilize annual or monthly average avoided energy. Hourly load shapes provided by NWA bidders should consider variation in measure performance over time and should be adjusted to represent average performance over the measure life. Such assumptions are typical in energy testing, and representative 8760 load shapes are leveraged by many platforms including NREL's REopt Tool[8].

3.2.2 Generator Capacity: Explicitly Included, Calculated

Generation Capacity Cost Impacts occur when the amount of installed capacity (i.e., kW) required to meet the utility's forecasted net load (accounting for reserve margin) decreases. If an NWA project results in a net decrease in load during the net system peak, the utility may experience benefits in the form of lower generation capacity needs. DERs may create a benefit in terms of reduced capacity for the utility through customer-sited generation or load reduction, and can also be referred to as "Avoided Generation Capacity Costs."

3.2.2.1 Calculation Responsibility and Test Inclusion

Generation capacity cost impacts will be calculated within Public Service's NWA CBA methodology using the equation and data inputs outlined below. This benefit is from the utility system perspective and will be included in the EMTRC, UCT, and RIM tests.

[8] https://reopt.nrel.gov/

3.2.2.2 Impact Equation and Variables

$$Avoided\ Generation\ Capacity_{\ y} = \frac{C_y * \Delta Pl_{G,N} * (1 + R)}{1 - L_{MP(D \rightarrow G)}} \qquad Equation\ 2$$

Equation variables are defined as follows:

$\boldsymbol{y}$ is a subscript indicating that a variable is year-specific.

$\boldsymbol{C}$ ($/kW-year) is the avoided generation capacity price.

$\Delta \boldsymbol{Pl_{G,N}}$ (kW) is the change in generation capacity based on net system demand that directly results from an implemented NWA and its associated measures.

$\boldsymbol{R}$ (%) is the utility's generation capacity reserve margin.

$\boldsymbol{L_{MP(D \rightarrow G)}}$ (%) is the utility's expected line loss factor from the installed DER to the generator. Depending on the DER location, the parameter could account for transmission losses or transmission & distribution losses.

3.2.2.3 Data Source and Assumptions

Avoided Generation Capacity Price ($\boldsymbol{C}$): The avoided generation impact calculation will utilize avoided generation capacity prices from Public Service's 2024 Vision Plan.

Change in Net Load ($\Delta \boldsymbol{Pl_G}$): The NWA project bidder will provide one 8760 forecasted hourly measure load shape which is representative of the average performance of the DER during its lifetime. Measure load shapes should be forecasted using TMY3 weather data from 2017, in order to align weather conditions, holidays, and days of the week across CBA calculations. The generation capacity peak definition will be derived from utility system net demand data from Public Service's 2024 Vision Plan using methods described in section 4.6.

Reserve Margin ($\boldsymbol{R}$): The NWA CBA methodology will use a reserve margin of 18% based on testimony delivered as a part of Public Service's ERP (see proceeding 21A-0141E).

Line Loss Rates ($\boldsymbol{L_{MP(D \rightarrow G)}}$): This equation will utilize marginal peak demand line loss rates calculated from Public Service's most recent line loss study. Appropriate line loss rates (distribution vs. distribution and transmission) will be selected based on the location of installed DER.

3.2.2.4 General Considerations

The system coincident peak definition that is used for the calculation of this value stream is distinct from the non-coincident peak definition is utilized for the distribution capacity impact, due to the location and equipment specific nature of the peak and central focus of this value stream for NWA projects.

3.2.3 Environmental Compliance: Implicitly Included, Calculated

Environmental Compliance Cost Impacts are due to a utility's regulatory obligations to reduce emissions from energy generation. Such regulations can include federal, regional, state, or local mandates. Both air quality emissions compliance costs (for requirements such as coal scrubbers) and GHG emissions reduction goal compliance costs are included in the avoided energy costs of the preferred pathway in the latest Public

Service Colorado 2024 Vision Plan. Because these costs are accounted for within the energy generation impact calculation, additional environmental compliance cost impacts will not be separately calculated within Public Service's NWA CBA methodology to avoid double counting the impact.

3.2.4 Transmission System Losses: Implicitly Included, Calculated

Transmission System Loss Impacts occur when DERs cause a change in end-use consumption that reduces or increases required electricity transmission and therefore transmission losses. Since transmission system losses are included explicitly in the calculation for transmission capacity cost impacts, generation capacity impacts and avoided energy generation impacts, transmission system loss impacts will not be included as an incremental value stream within the NWA CBA test. Transmission system loss impacts can also be caused by projects that result in lower transmission system loss rates. Since NWA projects will be targeted towards distribution system projects, this type of transmission system loss impact is not relevant.

3.2.5 Distribution Capacity: Explicitly Included, Calculated

Distribution Capacity Cost Impacts occur when measures implemented as a part of an NWA solution result in peak load relief and/or operational flexibility that reduce the distribution capacity required to safely and reliably deliver electricity. In the case of Public Service's NWA CBA test, this impact will be the distribution deferral benefit stream, where load reductions and operational flexibility help to defer the need for capital investment in distribution infrastructure. This is distinct from most of the other utility system value streams, in that the impact calculation is specific to an actual location-specific asset being considered, rather than based on system wide averages. The value of distribution deferral will be calculated as the difference in NPV between the investment made in the planned year, and the investment made at the end of the 10-year load forecast (depending on the planned year of the investment). The value of the distribution deferral will only be claimed if the NWA is able to provide enough load relief and operational flexibility that the system risk relief requirement (SRRR) is satisfied as described in section 4.3, indicating that the proposed distribution investment can be deferred with a reasonable degree of certainty. Since NWAs must be able to meet the SRRR in order to be considered as a viable solution for distribution deferral, this value will always be claimed for NWAs that pass initial suitability screenings.

3.2.5.1 Calculation Responsibility and Test Inclusion

Distribution capacity cost impacts will be calculated within Public Service's NWA CBA methodology using the equation and data inputs outlined below. This benefit is from the utility system perspective and will be included in the EMTRC, UCT, and RIM tests.

3.2.5.2 Impact Equation and Variables

$$Distribution\ Deferral = K_n - \frac{K_n}{(1+r)^{\Delta t}} \qquad Equation\ 3$$

Equation variables are defined as follows:

$\boldsymbol{n}$ is a subscript indicating the year of a planned distribution investment.

$\boldsymbol{K}$ ($) is the value of the planned distribution capital investments.

$\boldsymbol{r}$ (%) is the discount rate assumed for the specific CBA test the value stream is being calculated for. See section 4.2 for a discussion on the discount rates assumed for each of the tests (EMTRC, UCT, RIM).

$\Delta \boldsymbol{t}$ (# years) is the change in timeline (number of years deferred) of the planned distribution capital investment resulting from the NWA implementation.

3.2.5.3 Data Source and Assumptions

Amount of Planned Distribution Investment (K): This value will be unique to each project and will be supplied by Public Service's Distribution Planning Team.

Discount Rates (r): See section 4.2 for a discussion on the discount rates assumed for each CBA test.

Number of Years Deferred (Δt): is the change in the timeline (number of years deferred) of the planned distribution capital investment resulting from the NWA implementation.

3.2.5.4 General Considerations

One of the key considerations tied to the distribution deferral benefit is the deferral window considered. This deferral window will be the difference between the original planned investment year and the projected deferral window. Public Service's DSP forecast projects system needs 10 years into the future. If it is assumed that Public Service will need at least 2 years to identify, solicit, install, and operationalize an NWA solution, then the solution would be able to defer investments starting in year 3 of the forecast. Therefore, with year 10 being the last year the projects can be deferred to, given that it is the last year of load forecast, the deferral window is capped at 7 years, which ensures complete usage of 10-year forecasts. For instance, if it is planned to occur in year 4, then the deferral period will be 6 years as the NWA case always assumes the traditional investment is pushed to year 10.

3.2.6 Distribution System Losses: Implicitly Included, Calculated

Distribution System Loss Impacts occur when DERs cause a change in end-use consumption that reduces or increases required electricity distribution and therefore distribution losses. Since distribution system losses are included explicitly in the calculation for the distribution Load Relief Provided (LRP) as described in Section 4.4, transmission capacity impacts, generation capacity impacts and avoided energy generation impacts, transmission system losses will not be included as an incremental value stream within the CBA methodology.

3.2.7 Distribution O&M: Explicitly Included, Calculated

Distribution O&M Impacts can happen when an NWA would change the level of spending to maintain the safe and reliable operation of distribution facilities. This includes maintenance of substations, wires, and poles, as well as repairs and replacements. Similarly to the distribution capacity benefit, this benefit is binary and is only claimed if the NWA is able to meet the SRRR. Since NWA must be able to meet the SRRR in order to be considered as a viable solution for distribution deferral, this value will always be claimed for NWA that pass initial suitability screenings.

3.2.7.1 Calculation Responsibility and Test Inclusion

Distribution O&M impacts will be calculated within Public Service's NWA CBA methodology using the equation and data inputs outlined below. This benefit is from the utility system perspective and will be included in the EMTRC, UCT, and RIM tests.

3.2.7.2 Impact Equation and Variables

$$Distribution\ O\&M\ Impacts = O_n - O_{n+\Delta t} \qquad Equation\ 4$$

Equation variables are defined as follows:

$\boldsymbol{n}$ is the year of planned distribution investment.

$\Delta\boldsymbol{t}$ (# years) is a subscript describing the change in timeline (number of years deferred) of the planned distribution capital investment as a result of the NWA implementation.

$\boldsymbol{O_n}$ ($) is the net present value of the planned distribution O&M investments if the investment were to occur in year $\boldsymbol{n}$ as planned
$\boldsymbol{O_{n+\Delta t}}$ ($) is the net present value of the planned distribution O&M investments if the investment were to occur in year $\boldsymbol{n} + \Delta\boldsymbol{t}$ as would occur if the NWA deferred the distribution capital investment.

3.2.7.3 Data Source and Assumptions

Amount of Planned O&M Investment ($\boldsymbol{O}$): This value will be unique to each project and will be supplied by Public Service's Distribution Planning Team.

Number of Years Deferred ($\Delta\boldsymbol{t}$): For this methodology the distribution deferral period is assumed to be 5 years, meaning the NWA must provide the calculated LRR for the full 5-year window of deferral.

3.2.8 Financial Incentives: Explicitly Included, Input

Financial Incentive Costs are incurred when financial incentives are provided by the utility to DER host customers to encourage DER implementation. The NSPM definition also includes incentives paid to other market actors, but for this methodology only the incentives being paid to host customers are included within this value stream. This is due to the difference in how incentives paid to host customers need to be treated for a EMTRC that includes host customer impacts (as the EMTRC does for Public Service's NWA methodology). Incentives paid to host customers are not included in the EMTRC, since the cost to the utility is a benefit to the host customer, and therefore the impacts offset. For this methodology, incentives paid to third parties are rolled into the program administration costs, since they do not have the same offsetting effect and so need to be counted in the EMTRC.

3.2.8.1 Calculation Responsibility and Test Inclusion

Financial incentive costs will be included as a user-defined input (as opposed to a calculation) within Public Service's NWA CBA test and will be provided by the bidder. This impact is a cost from the utility system

perspective and a benefit from the host customer perspective. Therefore, it will not be included in the EMTRC since the impacts offset, but the utility system cost will be included in the UCT and RIM tests.

3.2.8.2 General Considerations

It should be noted that this category does not include "incentives" paid to the bidder to implement the NWA project (or program). Public Service does not plan to offer performance-based incentives to the bidders separate from the payment requested by the bidder. Rather, Public Service plans for the payment of the bidder to be provided in levelized increments annually during the period that load relief is required, contingent on the NWA performing as expected. For CBA, the payment to the bidder is not broken down into sub-categories, but is instead treated as the program administration cost as discussed in the next subsection. This allows the bidder to request whatever payment they feel is competitive, inclusive of cost recovery and profit, and provides Public Service with the required information to evaluate the NWA from the different test perspectives desired.

3.2.9 Program Administration: Explicitly Included, Input

Program Administration Costs are incurred by the bidder executing the NWA program (or project) and/or Public Service and are related to the planning, marketing, implementation, and/or EM&V of an NWA project. These costs vary depending on NWA project (or program) specifics and are therefore an input into the methodology. To preserve the confidentiality of independent bidder operations and costs, this category should be inclusive of the full payment requested by the bidder for providing the NWA solution, net of any financial incentives that will be passed through the host customers installing the DER solutions. In this way, third-party bidders will not be required to disclose program administration costs separate from profits, since the only aspect of concern from Public Service's standpoint for CBA analysis is the total dollar amount that is being paid to the bidder net of financial incentives provided to host customers, which as counted in the Financial Incentives value stream.

3.2.9.1 Calculation Responsibility and Test Inclusion

Program administration costs will be included as a user-defined input (as opposed to a calculation) within Public Service's NWA CBA methodology and will be provided by both the bidder and/or Public Service, depending on the required administration and EM&V. This cost is from the utility system perspective and will be included in the EMTRC, UCT, and RIM tests.

3.2.9.2 General Considerations

This category is labeled as Program Administration to follow the NSPM framework, but this term has a strong association with DSM programs. A more representative title would be "Requested Bidder Payment" for the reasons discussed at the beginning of this subsection.

3.2.10 Utility Performance Incentives

Utility Performance Incentives occur when a utility is offered financial incentives for meeting specified performance metrics related to an NWA project. These performance incentives can take many forms such as shared savings mechanisms, payments for meeting energy or capacity savings targets, or combinations of the above. Public Service is proposing a shared savings mechanism for NWAs. This means that any cost savings

attributable to the NWA solution compared to the traditional utility solution would be shared between their customers and Public Service. Public Service is proposing to use a 70:30 allocation. In other words, 70% of any potential savings resulting from an NWA compared to a traditional utility solution will accrue to customers, while the remaining 30% will accrue to the Public Service. The Public Service expects that performance incentive allocations will be litigated in future DSPs and therefore may be subject to modification as part of this methodology.

3.2.10.1 Calculation Responsibility and Test Inclusion

Utility performance incentives will be included as a user-defined input (as opposed to a calculation) within Public Service's NWA CBA test and will be provided by Public Service. This impact is from the utility system perspective and will be included in the EMTRC, UCT, and RIM tests.

3.2.10.2 General Considerations

The EMTRC, UCT and RIM tests can be determined with and without the performance incentive, as outlined in the DSP rulemaking.

3.2.11 Risk: Implicitly Included, Calculated

Risk Cost Impacts from the utility perspective can occur when the installation of an NWA project impacts operational, technology, cybersecurity, financial, legal, reputational, and/or regulatory risks. In the case of an NWA project, the biggest risk is whether the NWA will be able to mitigate the need for the distribution upgrade. This risk is accounted for in the formulation of the SRRR (see section 4.3). Therefore, risk is not included as a standalone impact since the impact is accounted for in the distribution capacity value stream.

3.3 Distribution Service Area Customer Impacts

3.3.1 Reliability: Explicitly Included, Calculated

Reliability Cost Impacts from a distribution service area customer perspective occur when reliability is increased for customers on a particular substation or feeder due to upgraded distribution equipment that replaces older, less reliable assets. Like the host customer reliability impact, a traditional utility system will impact the reliability for all the customers in the said distribution service area. This value can be captured by quantifying the change in the probability of a system outage due to the distribution system asset failure.

3.3.1.1 Impact Equation and Variables

$$DSAC\ Reliability = \left(P_{outage\ pre-investment} - P_{outage\ post-investment} \right) * Outage_{Duration} * VoLL \qquad Equation\ 5$$

Equation variables are defined as follows:

$\boldsymbol{P_{outage\ pre-investment}}$ (%) is the annual average probability of a system outage for a customer due to a distribution system asset failure.

$\boldsymbol{P_{outage\ post-investment}}$ (%) is the improved annual average probability of a system outage for a customer due to a distribution system asset failure.

$\boldsymbol{Outage_{Duration}}$ (hours) is the annual average outage duration due to distribution system failure that any given customer would experience.

$\boldsymbol{VoLL}$ ($/CMO) is the Value of Lost Load (VoLL), which attempts to assess the cost of the risk for an outage minute from the customer perspective.

3.3.1.2 Data Sources and Assumptions

Annual Average Probability of a System Outage ($\boldsymbol{P_{outage\ pre-investment}}$, $\boldsymbol{P_{outage\ post-investment}}$): These inputs will be project specific and modeled internally by Public Service.

Average Annual Outage Duration ($\boldsymbol{Outage_{Duration}}$): As a proxy, the System Average Interruption Duration Index (SAIDI) will be used, which will be supplied by Public Service's Distribution System Performance Team.

Value of Lost Load: ($\boldsymbol{VoLL}$): Public Service will provide the VoLL for the region of the installed NWA project per customer.

3.4 Lost Revenue and Rate Impacts

3.4.1 Utility Lost Revenue/Customer Bill Savings: Explicitly Included, Calculated

Utility Lost Revenue (also known as **Customer Bill Savings**) occurs when customer utility bills are reduced because of an NWA project, either through demand-side management measures or through on-site energy generation that offsets a customer's load, thereby reducing a utility's revenue from electricity sales.

3.4.1.1 Calculation Responsibility and Test Inclusion

Utility lost revenue will be calculated within Public Service's NWA CBA methodology using the equation and data inputs outlined below. This value stream will only be included in the context of the RIM test. The NWA CBA methodology will utilize a simplified calculation method compared to full-scale tariff testing to balance complexity and accuracy.

3.4.1.2 Impact Equations and Variables

$$Utility\ Lost\ Revenue_y = Pr_{y,h} * \Delta E_h + Pe_y * \Delta Pl \qquad Equation\ 6$$

Equation variables are defined as follows:

$\boldsymbol{y}$ is a subscript indicating that a variable is year-specific.

$\boldsymbol{h}$ is a subscript indicating that a variable should reflect hourly changes in value and should be determined using 8760 hourly data.

$\boldsymbol{Pr}$ ($/kWh) is the retail price of energy for a customer.

$\Delta\boldsymbol{E}$ (kWh) is the change in energy at the installation point of the DER during each hour that directly results from the implemented NWA and its associated measures. This change will vary temporally and in magnitude depending on the implemented measures and their operating profile.

$\boldsymbol{Pe}$ ($/kW) is the retail peak demand price for a customer (if applicable).

$\Delta\boldsymbol{Pl}$ (kW) is the change in peak load that directly results from an implemented NWA and its associated measures. The test will assume that customer peak demand period is same as utility system peak demand period. System peak periods will be determined using the methods set forth in section 4.6.

3.4.1.3 Data Source and Assumptions

Retail Price of Energy ($\boldsymbol{Pr}$): The NWA CBA methodology will include average 8760 price inputs for three separate customer types (residential, small commercial, and commercial and industrial) sourced from Public Service's published tariffs (inclusive of all riders and fees). The test will also allow the user to input their own 8760 retail price data.

Change in Energy ($\Delta\boldsymbol{E}$): The NWA project bidder will provide one 8760 forecasted hourly measure load shape which is representative of the average performance of the DER during its lifetime. Measure load shapes should be forecasted using TMY3 weather data from 2017, in order to align weather conditions, holidays, and days of the week across CBA calculations.

Retail Peak Demand Price (Pe): This input will be sourced from Public Service's published tariffs.[9] These values will vary by season and customer type according to the tariffs.

Change in Peak Load (ΔPl): The NWA project bidder will provide one 8760 forecasted hourly measure load shape which is representative of the average performance of the DER during its lifetime. Measure load shapes should be forecasted using TMY3 weather data from 2017, in order to align weather conditions, holidays, and days of the week across CBA calculations. The NWA load shape will be compared against a sample of individual customer load shapes in order to determine the impact on billed demand quantities.

3.4.1.4 General Considerations

Because the NSPM advocates that utility rate and bill analysis should be conducted separately from cost-effectiveness analysis, the utility lost revenue/customer bill savings impact will only be incorporated within the RIM test and will not be included in the UCT and EMTRC.

3.5 Host Customer Impacts

3.5.1 Host Customer Portion of DER Costs: Explicitly Included, Input

Host Customer Portion of DER. These costs should be included as an impact when an NWA program motivates a customer to make a purchase they would not have made otherwise. Host customer portion of DER costs should also be included as an impact when additional cost is incurred relative to an alternative consumer choice. The host customer portion of DER costs should include both incremental upfront costs for the asset, and incremental differences in the net present value of ongoing O&M for the measure.

3.5.1.1 Calculation Responsibility and Test Inclusion

Host customer portion of DER costs will be included as a user-defined input (as opposed to a calculation) within Public Service's NWA CBA methodology and will be provided by the NWA project bidder. The bidder should provide incremental costs incurred by host customers for each measure within their NWA program broken out by upfront costs and ongoing O&M. The value should be provided in nominal dollars ($). This impact is from the host customer perspective and will be included in the EMTRC.

3.5.1.2 General Considerations

Bidders calculating the host customer portion of DER costs should take care to establish an accurate baseline scenario by which to compare their solution costs. In scenarios where new technologies are being introduced that would not otherwise have been adopted by a host customer, all costs incurred by the host customer may be incremental to what they would have otherwise spent. For example, if an NWA program includes an incentive for customers to install a battery energy storage system ("BESS"), and a customer would not have purchased a BESS without the program incentive, the cost of the BESS that is paid for by the customer should be included as a host customer cost in the CBA. However, in situations where the NWA solution requires upgrades to already existing and/or necessary host customer fixtures (e.g., upgrading a refrigerator to a more energy efficient model), the baseline should represent a more standard option compared to the upgrade incentivized by the utility or bidder. In this case, the incremental costs to the host customer would be those incurred above the cost of the standard option. For example, if a host customer were looking to purchase a

[9] https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/PSCo_Electric_Entire_Tariff.pdf

standard thermostat, but a program incentive influences them to instead purchase a smart thermostat, then any incremental cost above the purchase price and ongoing O&M costs of a standard thermostat should be included as an impact.

Utility financial incentives should not be subtracted from the calculated incremental DER cost since financial incentives are accounted for from the utility system perspective. Interconnection costs should not be accounted for in this impact, and are instead captured in Interconnection fees, described in Section 3.5.3.

3.5.2 Host Transaction Costs: Not Applicable

Host Transaction Cost Impacts are indirect costs incurred by a host customer to install DER on their premise. These costs could include time spent collecting information, obtaining quotes from vendors, filing paperwork, and/or completing applications for rebates or other financing mechanisms. This host customer value stream is most commonly qualified by the hourly earnings of the host customer, multiplied by the incremental invested time. However, this inherently assumes that each hour invested in the DER procurement for the host customer results in a lost hour of earnings. That is not typically the case, and not reflective of the way the individuals usually decide what type of voluntary activities to engage in. Therefore, Public Service is not including this value stream within the CBA methodology.

3.5.3 Interconnection Fees: Explicitly Included, Input

Interconnection Fees are costs associated with utility interconnection processes that are paid by a DER host customer. These fees are applicable and relevant when an NWA project requires the utility to do work (such as conducting studies or upgrading equipment) to interconnect a DER with their system, and the host customer is required to pay for associated services and/or equipment. This value will be included within the EMTRC, UCT, and RIM tests.

3.5.3.1 Calculation Responsibility and Test Inclusion

Interconnection fees will be included as a user-defined input (as opposed to a calculation) within Public Service's NWA CBA test and will be provided by Public Service. This benefit is from the host customer perspective and will be included in the EMTRC, UCT, and RIM tests within the NWA CBA test.

3.5.3.2 General Considerations

In this CBA the interconnection fee charged to the host customer is counted as a host customer cost. Note that if the utility didn't charge the host customer a fee and instead took the burden of the interconnection cost, then it would instead be a utility system cost.

3.5.4 Reliability: Explicitly Included, Calculated

Reliability Cost Impacts from a host customer perspective occur when an installed DER has a direct impact on a customer's ability to receive consistent power, either by preventing outages or by reducing the length of such events. In the context of an NWA, host customer reliability increases when an installed DER has the potential to reduce host Customer Minutes Out (CMO) compared to other, similar customers that do not have the DER installed on their premise in the same region. Reliability value is quantified for the two types of DERs

that have the ability to reduce CMO, standalone BESS and a solar PV and BESS combination, using a single equation. This calculation multiplies the reduction in CMO by the Value of Lost Load (VoLL) to the customer to determine the total reliability benefit to the host customer.

3.5.4.1 Calculation Responsibility and Test Inclusion

Reliability cost impacts will be calculated within Public Service's NWA CBA methodology using the methods outlined below. This benefit is from the host customer's perspective and will be included in the EMTRC.

3.5.4.2 Impact Equations and Variables

For measures with $L - (SC * CF * SF) > 0$:

$$\Delta CMO = \boldsymbol{MINIMUM}(\ CMO, \qquad CMO - \left(\frac{SOC - SOC_{min} * BEC}{L}\right)) \qquad Equation\ 7$$

For measures with $L - (SC * CF * OM)\ \leq 0$:

$$\Delta CMO = CMO \qquad Equation\ 8$$

For all measures:

$$Increased\ Reliability\ =\ \Delta CMO * VoLL \qquad Equation\ 9$$

Equation variables are defined as follows:

$\boldsymbol{BEC}$ (kWh) is the usable energy capacity of the BESS.

$\boldsymbol{CF}$ (%) is the capacity factor of the PV Array if present as part of an NWA.

$\boldsymbol{CMO}$ (minutes) is the annual average Customer Minutes Out (CMO) per customer for the region of the installed NWA project. As a proxy, the jurisdiction specific System Average Interruption Duration Index (SAIDI) will be used, which will be supplied by Public Service's Distribution System Performance Team.

$\Delta\boldsymbol{CMO}$ (minutes) is the calculated change in CMO.

$\boldsymbol{L}$ (kW) is the annual average host customer load.

$\boldsymbol{SC}$ (kW) is the nameplate capacity of a PV Array if present as part of an NWA.

$\boldsymbol{OM}$ (%) is the operating margin of an NWA solution, which is a safety factor to account for the intermittency of the solar PV array if present as part of an NWA and combined with storage.

$\boldsymbol{SOC}$ (%) is the annual average state of charge for a BESS.

$\boldsymbol{SOC_{min}}$ (%) is the minimum desired state of charge for the BESS.

$\boldsymbol{VoLL}$ ($/CMO) is the Value of Lost Load (VoLL), which attempts to assess the cost of the risk for an outage minute from the customer perspective.

3.5.4.3 Data Source and Assumptions

$\boldsymbol{BEC, CF, L, SC, SOC, SOC_{min}}$: This data will be very specific to the DER proposed as part of the NWA and will be provided as a bidder input.

$\boldsymbol{CMO}$**:** Public Service will provide annual customer minutes out (CMO) for the region of the installed NWA project per customer.

$\boldsymbol{OM}$ **:** The operating margin will be a 25% adder to the duration and magnitude of the system relief requirement.

$\boldsymbol{VoLL}$**:** Public Service will provide the VoLL for the region of the installed NWA project per customer.

3.5.4.4 General Considerations

It is important to note that increased reliability can only be realized with storage or similar assets since such assets can provide backup power for customers. Solar cannot be relied upon by itself since the resource is intermittent. While other EE measures may improve the conditions during an outage, such measures will not increase electricity reliability for host customers.

3.5.5 Resilience: Not Applicable

Resiliency Cost Impacts from a host customer perspective occur when customers can anticipate, prepare for, and adapt to changing conditions and withstand, respond to, and recover rapidly from power disruptions. Distinct from reliability, which is focused on expected day to day operations, resiliency is focused on severe impact, long duration events such as wildfires, floods, and hurricanes. The reliability benefit already accounts for potential reductions in customer outage time, and takes into account the average historic CMO. It is therefore representative of the reduction in outage benefit that a host customer can reasonably expect from a probabilistic standpoint. Given the low likelihood and unexpected nature of the type of severe weather events which resiliency benefits are focused on, a distinct benefit stream has not been quantified. This accounts for the high degree of uncertainty in predicting this value stream, and is itself a hedge against risk, as it means that there are is no inclusion of benefits which have a low likelihood of realization.

3.5.6 Host Customer and Disproportionally Impacted Communities (DIC) NEIs: Explicitly Included, Calculated

Host Customer and DIC NEI Cost Impacts are benefits and costs of DERs that are separate from energy-related impacts such as asset value, economic wellbeing, health and safety, comfort, productivity, satisfaction and pride, and empowerment and control. Historically, these values have been difficult, time intensive, or expensive to quantify using established methods. Because of this, many jurisdictions represent NEI impacts in the form of a proxy or adder on top of other benefits.

3.5.6.1 Calculation Responsibility and Test Inclusion

Host customer and DIC NEIs will be calculated within Public Service's NWA CBA methodology using the methods outlined below. This benefit is from the host customer perspective and will be included in the EMTRC.

3.5.6.2 General Considerations

Host customer and DIC NEIs will be calculated by multiplying the sum of all utility system benefits by the appropriately selected NEI adder. The Public Commission approved the 2024-2026 Public Service's DSM and Beneficial Electrification plan[10] in December 2024. This plan includes a 10% NEI adder for standard customers and a minimum 25% NEI adder for income qualified customers. The adders will be applied as follows:

A) 10% NEI adder for natural gas programs,

B) 10% NEI adder for electric programs, and

C) 25% NEI adder for income qualified natural gas and electric programs.

3.6 Societal Impacts

3.6.1 GHG Emissions, CO_2: Explicitly Included, Calculated

GHG Emissions Cost Impacts are a result of changes in the amount of fossil-fueled electricity generation within a utility's service territory. Reduction in carbon dioxide emissions typically represents a benefit to society because of the resulting improvements to public health, the environment, and more.

3.6.1.1 Calculation Responsibility and Test Inclusion

GHG Emissions Cost Impacts will be calculated within Public Service's NWA CBA methodology using the methods outlined below. This benefit is from the societal perspective and will be included in the EMTRC.

3.6.1.2 Impact Equations and Variables

$$GHG\ Impacts = SCC_y * E_{GHG,h,y} * \frac{\Delta E_h}{L_{ME(D \rightarrow G)}} \qquad Equation\ 10$$

$\boldsymbol{y}$ is a subscript indicating that a variable is year-specific.

$\boldsymbol{h}$ is a subscript indicating that a variable should reflect hourly changes in value and should be determined using 8760 hourly data.

$\boldsymbol{SCC}$ ($/ton) is the Societal Cost of Carbon emissions.

$\boldsymbol{E_{GHG}}$ (tons/kWh) is the long run marginal emissions rate of the electricity grid at the generator level. This value includes all GHG emission rates except for methane which is accounted for in a separate calculation.

$\Delta \boldsymbol{E}$ (kWh) is the change in energy at the installation location of the DER during each hour that directly results from the implemented NWA and its associated measures.

[10] 2024-2026 Demand-Side Management & Beneficial Electrification Plan. Public Service Company of Colorado. Proceeding No. 23A-0589EG. Dec 6, 2024.

$L_{ME(D\rightarrow G)}$ (%) is the utility's expected marginal energy line loss factor from the location of the installed DER to the generator. Depending on the DER location, the parameter could account for transmission losses or transmission & distribution losses.

3.6.1.3 Data Source and Assumptions

Social Cost of Carbon (SCC) : Public Service will utilize the February 2021 SCC from the Biden Administration at 2.5% discount rate.

Emissions Rate (E_{GHG}) : Are provided by Public Service's 2024 Vision Plan from the approved ERP. These are provided as hourly emissions rates (8760s) for 2022-2045. When valuing GHG emissions in a planning context, the long run marginal emissions rates should be utilized. This is because they reflect the marginal change in emissions that can be planned for. In the absence of long run marginal rates, average projected emission rates are an appropriate proxy, as they are closer on average to long run marginal than short run marginal rates.

Change in Energy (ΔE) : The NWA project bidder will provide one 8760 forecasted hourly measure load shape which is representative of the average performance of the DER during its lifetime. Measure load shapes should be forecasted using TMY3 weather data from 2017, in order to align weather conditions, holidays, and days of the week across CBA calculations.

Line Losses ($L_{ME(D\rightarrow G)}$) **:** The calculation will utilize marginal energy line loss rates calculated from Public Service's most recent system loss study. An appropriate line loss rate (distribution vs. distribution and transmission) will be selected based on the location of the DER.

3.6.1.4 General Considerations

Public Service is required to use the EPA's SCC values based on state legislation. Therefore, the value of the GHG emissions impact will be determined by multiplying the SCC per metric ton of CO_2 by the estimated CO_2 reduction from the implemented NWA solution. It should be noted that as emissions are increasingly reduced on Public Service's system the average emissions rates will continually decrease.

3.6.2 GHG Emissions, Methane: Included explicitly, Calculated

Methane Emission Cost Impacts are a result of changes in the amount of fossil-fueled electricity generation within a utility's service territory. Reduction in emissions typically represents a benefit to society because of the resulting improvements to public health, the environment, and more.

3.6.2.1 Calculation Responsibility and Test Inclusion

Methane Emissions Cost Impacts will be calculated within Public Service's NWA CBA methodology using the methods outlined below. This benefit is from the societal perspective and will be included only in the EMTRC.

3.6.2.2 Impact Equations and Variables

$$GHG\ Impacts = \quad SCM_y * EM_{Methane,h,y} * \frac{\Delta E_h}{L_{ME(D\rightarrow G)}} \qquad Equation\ 11$$

y is a subscript indicating that a variable is year specific.

$\boldsymbol{h}$ is a subscript indicating that a variable should reflect hourly changes in value and should be determined using 8760 hourly data.

$\boldsymbol{SCM}$ ($/ton) is the Social Cost of Methane emissions.

$\boldsymbol{EM_{Methane}}$ (tons/kWh) is the long-run marginal emissions rate for methane of the electricity grid at the generator level.

$\Delta\boldsymbol{E}$ (kWh) is the change in energy at the installation location of the DER during each hour that directly results from the implemented NWA and its associated measures.

$\boldsymbol{L_{ME(D\rightarrow G)}}$ (%) is the utility's expected marginal energy line loss factor from the location of the installed DER to the generator. Depending on the DER location, the parameter could account for transmission losses or transmission & distribution losses.

3.6.2.3 Data Source and Assumptions

Social Cost of Methane ($\boldsymbol{SCM}$): Public Service will utilize the February 2021 SCM from the Biden Administration at a 2.5% discount rate.

$\boldsymbol{EM_{Methane}}$ (tons/kWh) is the long-run marginal methane emissions rate of the electricity grid at the generator level.

$\Delta\boldsymbol{E}$ (kWh) is the change in energy at the installation location of the DER during each hour that directly results from the implemented NWA and its associated measures.

$\boldsymbol{L_{ME(D\rightarrow G)}}$ (%) is the utility's expected marginal energy line loss factor from the location of the installed DER to the generator. Depending on the DER location, the parameter could account for transmission losses or transmission & distribution losses.

3.6.3 Public Health: Explicitly Included, Calculated

Public Health Cost Impacts occur when air quality and human health is deteriorated due to increased concentrations of pollutants like $PM_{2.5}$, SO_2 and, NO_X. These pollutants are released into the atmosphere from fossil-fuel based combustion for electricity generation and natural gas combustion for other uses. This methodology quantifies the impact of the NWA solution on air quality and human health using the EPA COBRA Tool and marginal emissions from the 2024 Vision Plan.

3.6.3.1 Calculation Responsibility and Test Inclusion

Public Health impacts will be calculated within Public Service's NWA CBA test using the equation and data inputs outlined below. This benefit is from the societal perspective and will be included in the EMTRC.

3.6.3.2 Impact Equations and Variables

$$Public\ Health\ Impacts\ =\ EF_{P,y,h} * \frac{\Delta E_h}{L_{ME(D\rightarrow G)}} * COBRA_P \qquad Equation\ 11$$

Equation variables are defined as follows:

$\boldsymbol{P}$ is a subscript that indicates that a variable should represent value associated with each relevant pollutant including $PM_{2.5}$, SO_2 and NO_X.

$\boldsymbol{y}$ is a subscript indicating that a variable is year specific.

$\boldsymbol{h}$ is a subscript indicating that a variable should reflect hourly changes in value and should be determined using 8760 hourly data.

$\boldsymbol{COBRA_P}$ ($/ton) is the economic value of pollutant reduction due to improvements in human health per ton of pollutant decreased as calculated by the EPA COBRA Tool[11].

$\boldsymbol{EF_{P,h}}$ (ton/kWh) is a measure of the intensity of pollutant emissions due to electricity consumption. The value estimates the amount of pollution released for every unit of energy produced and consumed.

$\Delta\boldsymbol{E_h}$(kWh) is the change in energy at the installation location of the DER that directly results from the implemented NWA and its associated measures.

$\boldsymbol{L_{ME(D\rightarrow G)}}$ (%) is the utility's expected marginal energy line loss factor from the location of the installed DER to the generator. Depending on the DER location, the parameter could account for transmission losses or transmission & distribution losses.

3.6.3.3 Data Source and Assumptions

$\boldsymbol{COBRA_P}$: This value will be calculated using the EPA COBRA Tool as outlined above.

Emissions Factors ($\boldsymbol{EF_{P,h}}$) : The emissions factors will be provided by Public Service and based on the 2024 Vision Plan.

Change in Energy ($\Delta\boldsymbol{E_h}$): The NWA project bidder will provide one 8760 forecasted hourly measure load shape which is representative of the average performance of the DER during its lifetime. Measure load shapes should be forecasted using TMY3 weather data from 2017, in order to align weather conditions, holidays, and days of the week across CBA calculations.

Line Losses ($\boldsymbol{L_{ME(D\rightarrow G)}}$): The calculation will utilize marginal energy line loss rates calculated from data in Siemens PTI Report Number R005-14, *Electric System Loss Analysis,* prepared for Public Service Colorado. Appropriate line loss rates (distribution vs. distribution and transmission) will be selected based on the location of the DER.

3.7 Other Fuel Impacts

3.7.1 Natural Gas Supply Cost, Explicitly Included, Calculated

Natural Gas Supply Cost Impacts are quantified by estimating the impact of an NWA solution on the amount of natural gas needed to be supplied to a customer by the utility. Typically, weatherization and electrification measures will have the largest impacts on natural gas since such measures will reduce or eliminate the amount of natural gas needed to power critical loads such as heating. This value does not include impacts to the amount of electricity produced by and consumed from natural gas fueled power plants.

[11] https://cobra.epa.gov/

3.7.1.1 Calculation Responsibility

Natural Gas Supply Costs will be calculated within Public Service's NWA CBA methodology using the equation below. This benefit will be included in the EMTRC.

3.7.1.2 Impact Equations and Variables

$$Natural\ Gas\ Supply\ Impact\ = \frac{\Delta NG_m}{L_{NG}} * NGAC_m \qquad Equation\ 12$$

Equation variables are defined as follows:

$\boldsymbol{m}$ is a subscript indicating that a variable is month specific.

$\Delta \boldsymbol{NG_m}$ (therm) is the estimated change in natural gas usage due to a measure for each month of the year on average during the measure lifetime. This impact will be an input from the NWA project bidder.

$\boldsymbol{NGAC_m}$ ($/therm) is the avoided cost of natural gas supply.

3.7.1.3 Data Source and Assumptions

Change in Natural Gas Consumption ($\Delta \boldsymbol{NG_m}$): The change in natural gas use will be provided as an input from the NWA project bidder.

Natural Gas Avoided Cost ($\boldsymbol{NGAC_m}$) : This data will be taken from Public Service's 2024 Vision Plan data.

3.7.1.4 General Considerations

The natural gas impacts are included in the EMTRC since Public Service is a dual fuel utility, providing customers with electricity, natural gas, or a combination of the two.

4 Key Analysis Assumptions

4.1 Accounting Assumptions

Public Service's NWA CBA test will be conducted using nominal dollar values and discount rates (as opposed to real dollar values and discount rates) in alignment with the approved ERP and Public Service's internal practices.

4.2 Discount Rates

Public Service's WACC will be used as the discount rate for the EMTRC. Public Service's after tax WACC is 6.52% for the electric business.[12]

[12] See Proceeding No. 21AL-031&E

4.3 System Risk Relief Requirement

The peak period and system relief requirement for the distribution deferral will be unique to each specific NWA opportunity considered based on the loading of the device or equipment on where the NWA is being installed. To calculate the system relief requirement, the Public Service NWA CBA methodology will use an approach that minimizes system risk by considering maximum system needs from an expected overage amplitude and duration perspective. Depending on the nature of the project being considered for potential NWA, this may include both N-0 and N-1 risks.

To determine the amplitude of the system relief requirement, Public Service will determine the highest expected overage, in MW or MVA, on the portion of the system being considered. An overage, in this case, is any system load that is above and beyond the load limit based on system constraints. Once the highest system overage is determined, a factor of safety of 25% will be added to account for any uncertainty in load forecasts and changing system and operational needs.

To determine the intraday duration of the system relief requirement, Public Service will identify the longest single duration of an overage on the portion of the system being evaluated. The length of this overage (in hours), plus a 25% safety factor, will represent the duration requirement of an NWA to align with amplitude of the system risk relief requirement

An NWA will be expected to be able to meet the System Risk Relief Requirement needs (in MW) for the entire duration of the longest potential overage. Therefore, the system relief requirement will reflect maximum system constraints both in terms of duration and magnitude. Public Service believes that this method will minimize system risk in terms of safety and reliability by ensuring that an NWA can meet worst-case, but not unrealistic, system needs.

4.4 System Risk Relief Provided

Public Service will require that proposed NWA solutions can be relied on to meet the entire system relief requirement (both magnitude and duration) up to 30 times within a specified 120 day period (continuous or non-continuous) of the year. The 120 day period will be specified within each NWA RFP.

NWA project bidders will be required to produce 8760 hourly load shapes for their proposed measures using TMY3 weather data and specified date times from Public Service so that Public Service is able to accurately compare bidder load and generation shapes against system needs. Public Service will then evaluate system conditions and identify attributes (such as weather, date, and time) to determine when peaks are likely to occur before determining up to 30 days within a specified 120 day window in which an NWA solution must meet the system relief requirement. Public Service will then assess system risk relief provided by the NWA during the specified peak days to determine if the system risk relief provided meets the system relief requirement. Public Service will provide peak times to NWA bidders in advance of their bid so that bidders can ensure that solutions meet system relief requirements.

4.5 Monthly Peak Demand

For the Utility Lost Revenue/Customer Bill Savings calculation, monthly customer peak demand must be calculated before and after an NWA installation to determine monthly demand charges for applicable

customer classes. Public Service will provide 8760 hourly, illustrative load profiles for each customer class eligible to receive a measure under an NWA proposal. 8760 hourly measure load shapes will then be subtracted from customer class load shapes and load before and after measure installations will be compared to determine the maximum demand in a single hour during each month. The difference in maximum demand before and after measure installation represents the impact of a measure on utility demand charge collections. Methods for determining monthly demand are in line with Public Service's definition of "billing demand" within the April 2022 Electric Rate Book which states, "Billing Demand, determined by meter measurement, shall be the maximum fifteen (15) minute integrated Kilowatt Demand used during the Month." [13] It is important to note that there could be minor discrepancies in peak demand calculated vs. actual billing demand due to lack of easily accessible 15-minute customer and measure load data.

4.6 System Peak Definition

For generation capacity calculations, Public Service will need to include a broader system peak definition, rather than the NWA-specific system relief requirement. Public Service has provided 8760 hourly system net demand data from their Encompass model runs which inform Public Service's system planning exercises. The net demand is Public Service's system demand net of renewable production. This data can be used to determine the peak time for generation capacity benefit calculations. Public Service will determine the system peak by selecting the 50 highest hours of net demand on their system for the year that falls in the middle of the distribution deferral period. This allows for a simplified methodology in which as constant peak definition is assumed, rather than a dynamic year-specific system peak. The 50 highest net load hours will then be analyzed to extract the season, day type, hours and weather conditions that can be used to define when the peak most likely occurs. For example, the net peak definition could be classified as "summer weeknights between 5:00PM and 6:00PM Mountain Time (MT), when the temperature has exceeded 80 degrees Fahrenheit."

5 Appendix

5.1 Non-Applicable Potential Utility System Impacts

5.1.1 RPS/CEP Compliance: Not Applicable

RPS/CES Compliance Cost Impacts result from DERs reducing a utility's RPS/CES target by virtue of lowering overall electricity demand or increasing the level of qualified renewable generation. Colorado's RPS goals required 30% of IOU electricity sales to come from renewable sources by 2020. Public Service is currently significantly exceeding Colorado's RPS goals and will continue to do so as they decarbonize their grid under the approved pathway forward in the latest ERP and Clean Energy Plan. The approved plan (Phase I) exceeds Colorado's goals in emission reductions, protects reliability of the electrical system, and reduces costs for customers[14]. Therefore, there is no incremental value from the load impacts from NWA projects in regard to what it is costing Public Service to comply with RPS/CES goals.

5.1.2 Wholesale Market Price Effects: Not Applicable

Wholesale Market Price Effect Impacts occur when DERs reduce (or increase) the demand for electricity, thereby causing changes in wholesale market prices. This effect is sometimes referred to as Demand Reduction Induced Price Effect (DRIPE). Because Public Service is not a part of an organized wholesale market, and because Public Service has a relatively high and growing level of renewable energy on its system that is sometimes curtailed, it is unclear what the wholesale market price effects would be. Thus, the value would be zero and will not be included as a value stream within the NWA CBA methodology.

5.1.3 Ancillary Services: Not Applicable

Ancillary Services Cost Impacts occur when NWA measures reduce Public Service's need to self-supply services that help them to maintain the bulk power system, such as frequency regulation, voltage regulation, spinning reserves, and operating reserves. To realize ancillary services value from an NWA, Public Service would require real-time telemetry and dispatch control of the asset. Additionally, if the primary use-case of the NWA is to provide value to the distribution system, then the value associated with the secondary use-case of providing benefits to bulk system dispatch would be marginal and potentially in conflict with optimal dispatch of the asset for the bulk electric system. Therefore, it is assumed that there is no ancillary services value associated with an NWA.

5.1.4 Transmission Capacity: Not Applicable

Transmission Capacity Cost Impacts occur when measures implemented as a part of an NWA solution result in system peak load savings that reduce the transmission capacity required to safely and reliably transport

[14] PSCo began developing the CBA methodology prior to the filing of the updated Settlement Agreement on April 27, 2022 in Proceeding No. 21A-0141E. Calculation methodologies and new data were updated after the Commission's decision in March 2024.

electricity. With Public Service's existing plans for transmission capacity expansion[15], and with future transmission builds prioritizing movement from renewable generation to load centers (as opposed to servicing peak load), it is assumed that there is no incremental avoided transmission capacity value from an NWA project considered within the time horizon of this DSP. Therefore, transmission capacity cost impacts with not be included within the NWA CBA.

5.1.5 Distribution Voltage: Not Applicable

Distribution Voltage Impacts occur when DERs alter the amount that a utility has to spend on maintaining proper distribution system voltage. Since DERs typically increase voltage concerns, it is assumed that NWAs will not have a significant impact on deferring planned spending in this area. However, this could potentially be an area of future concern as increased penetration of DERs can lead to distribution voltage issues. However, given the site-specific nature of this concern and the lack of established methodologies for quantification[17], this impact is not considered as a part of the NWA CBA methodology.

5.1.6 Credit and Collection: Not Applicable

Avoided Credit and Collection Costs are the reductions in utility costs associated with delinquent customer payment of energy bills. This could be reductions in costs such as sending notices, customer terminations, disconnections, reconnections, carrying costs associated with arrears, and writing off bad debt. Public Service's anticipated changes to these internal utility costs as a result of NWA project implementation are minimal, therefore the value stream will not be included in the NWA CBA calculation.

5.1.7 Resilience: Not Applicable

Resilience Cost Impacts may occur if a DER contributes to the prevention of or rapid recovery from severe and long-duration outages. This is in keeping with the U.S. DOE definition of resilience[16] as the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions. Resilience is different from reliability because resilience is focused on minimizing the impact of *severe* and *long-duration* outages. Public Service does not anticipate that NWA projects will have any notable cost impact on utility system resilience. This is because if there are severe weather events that damage or destroy utility infrastructure, such as distribution lines, the work to fix the damaged infrastructure will not be reduced by the presence of DERs. Therefore, resiliency from a utility system standpoint will not be included as an input or a calculation in the NWA CBA test. There is, however, a significant host customer benefit that can be realized from DERs such as behind-the-meter storage as a result of reduced outage time. This benefit is quantified separately under the Host Customer Impacts section as part of host customer reliability.

[15] Public Utilities Commission of the State of Colorado, Proceeding No. 21A-0141E, *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan.*
[16] U.S. DOE 2017. Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review. Chapter IV: Ensuring Electricity System Reliability, Security, and Resilience. https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf

5.2 Non-Applicable Potential Host Customer Impacts

5.2.1 Risk: Not Applicable

Risk Cost Impacts from a host customer perspective can occur due to uncertainty including price volatility, power quality, outages, and operational risk related to failure of installed DER equipment and user error. This type of risk may vary depending on the type of DER. Given the multiple considerations and offsetting nature of the potential risk impacts for customers, combined with the lack of clearly established methodologies in this area[17], host customer risk impacts will not be included in the NWA CBA methodology.

5.2.2 Tax Incentives: Not Applicable

Tax Incentives at the local, state, and federal levels may be available for DER host customers as a mechanism to encourage DER adoption. Tax incentives can take many forms, but most commonly they are detracted from a host customer's income tax as a percent of total project costs. Tax incentives should only be included if they are a cash flow crossing into a jurisdiction, since incentives originating from within the jurisdiction are considered a transfer payment. Since federal, state, and local taxes all originate from within Public Service's territory and any tax incentives received from an NWA host customer would be a transfer payment back to host customers, there is no value attributed to tax incentives in the CBA tests.

5.3 Non-Applicable Potential Societal Impacts

5.3.1 Resilience: Not Applicable

Resilience Cost Impacts from a societal perspective are those experienced beyond utilities or host customers. For example, a hospital that can continue to operate during a power outage will provide societal benefits beyond those experienced by either the utility system or the individual host customer. Other critical facilities include fire and police departments, grocery stores, and other facilities essential for a community to function. While reducing outages for such facilities has significant societal benefit, it is assumed that all critical infrastructure is already required to have backup power available, therefore there would be no incremental resilience value from an installed NWA and associated measures.

5.3.2 Other Environmental, Not Applicable

Other Environmental Impacts are environmental impacts beyond GHG emissions and public health impacts. These impacts could include liquid and solid waste emissions, land and water use, and more. These have not been included in Public Service's NWA CBA methodology due to the ambiguity and variety of potential impacts, and lack of clear connection to policy supporting their inclusion.

[17] Methods, Tools and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis. March 2022. https://www.nationalenergyscreeningproject.org/resources/quantifying-impacts/

5.3.3 Low Income: Society, Not Applicable

Low Income: Society Cost Impacts are incremental to those that accrue to host customers. For instance, broader community poverty alleviation. Reliable methods for quantification of low-income: society impacts have not been established, and therefore these impacts will not be included within the NWA CBA methodology.[17]

5.3.4 Energy Security, Not Applicable

Energy Security Impacts occur when DER investments either reduce dependence on imported fuels and energy sources or increase cyber-security vulnerabilities by increasing the amount of networked connection to the electricity grid. There is a lack of existing methods and/or resources for inclusion of this impact within a CBA, therefore it will not be included within the NWA CBA methodology.[17]

5.4 Non-CBA Value Considerations

5.4.1 Utility System Reliability: Not Applicable

Reliability Cost Impacts may occur if an installed DER causes a reduction in customer electric service interruptions. The DOE defines reliability as the ability of the system or its components to prevent or withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components.[18] Aspects of reliability include transmission, distribution, and generation (adequacy and operational). Most of Public Service's electricity outages are caused by issues at the distribution system level.

Highlighted in the Colorado Quality Service Plan (QSP), there are two metrics that put a direct financial link to the reliability of the utility system. The metrics are Electric Continuity Threshold (ECT), and the Electric Restoration Threshold (ERT). Public Service is obliged to pay $50/customer-year to customers who exceeded ECT of more than five (5) sustained electric service interruptions, excluding Major Event Day interruptions and public damage interruptions. It is also obliged to pay $50/customer-year to customers that have outages longer than the 24 hours as it exceeds the ERT. While NWA solutions with energy storage capabilities hold the potential to alleviate the shorter duration outages or get rid of them altogether, such solutions would not reduce the penalty burden on Public Service since the metrics are designed around the utility providing service. If a customer is able to keep power during an outage due to an NWA, utility power is still considered unavailable to the customer and therefore provides no cost impact from a utility perspective. Additionally, Public Service and regulators do not have the capability to track whether a customer has DER that has actively prevented or shortened a customer outage, making it difficult for entities to measure the impact of an NWA on utility system reliability.

Reliability impacts also include the ability of a traditional infrastructure solution to allow a utility to operate the distribution system in multiple configurations due to both planned (e.g. planned outages and maintenance) and unplanned contingencies. Though this value is difficult to quantify and monetize for inclusion in a CBA, it will be considered separately when evaluating NWA proposals to ensure that system reliability is preserved to the extent possible.

5.4.2 DER Hosting Capacity

Hosting Capacity Benefits occur when a traditional infrastructure solution increases DER hosting capacity on the distribution system and therefore may reduce the need for separate upgrades which would be paid for by the interconnection customer. While this value will not be included within the CBA because of difficulties in monetizing the value, it will be included as a separate consideration as Public Service evaluates NWA proposals.

5.4.2.1 Impact Equation and Variables

$$Hosting\ Capacity\ Benefit\ (MVA) = Equipment\ Amp\ Rating * Nominal\ Voltage * \sqrt[3]{}$$

[18] U.S. DOE 2017. Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review. Chapter IV: Ensuring Electricity System Reliability, Security, and Resilience. https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf

$$Equation\ 12$$

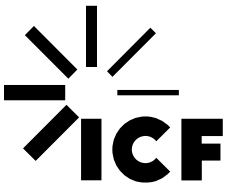
5.4.3 Distribution Service Area Economic Development

Distribution Service Area Economic Development Impacts occur when headroom is created by traditional utility investments which can allow new customer loads to be expediently, and cost effectively connected to the distribution system. Though this value is difficult to quantify a distinct and monetizable value for inclusion in a CBA, it will still be considered qualitatively in tandem with the CBA and other non-CBA value considerations.

5.4.4 Societal Economic and Jobs

Societal Economic and Jobs Impacts occur when an NWA project results in increased economic activity and job creation in a utility's jurisdiction. This value is often represented via metrics such as job-years, personal income, state GDP, and/or state tax revenues, and can be divided as direct impacts, indirect impacts, and induced impacts. While DER deployment due to NWA may result in economic benefits to a jurisdiction, there is significant overlap between economic analysis and cost-effectiveness testing, meaning that the inclusion of economic and jobs impacts within the CBA would impose a high risk of double counting. Therefore, this impact will not be included within any of the NWA CBA tests.

However, since Public Service and the state of Colorado are committed to a just transition to clean energy resources, economic and jobs impacts should still be a consideration in the assessment of NWA viability. Therefore, Public Service will require NWA project bidders to quantify job-years created by their proposed project, which will be included as a separate consideration when evaluating NWA benefits and costs.




twitter.com/ICF


linkedin.com/company/icf-international


facebook.com/ThisIsICF


#thisisicf

icf.com

About ICF

ICF (NASDAQ:ICFI) is a global consulting and digital services company with over 7,000 full- and part-time employees, but we are not your typical consultants. At ICF, business analysts and policy specialists work together with digital strategists, data scientists and creatives. We combine unmatched industry expertise with cutting-edge engagement capabilities to help organizations solve their most complex challenges. Since 1969, public and private sector clients have worked with ICF to navigate change and shape the future. Learn more at icf.com.

Appendix 3 - NWA Model Contract and Redline

NON-WIRES ALTERNATIVE
SERVICES AGREEMENT

BETWEEN

PUBLIC SERVICE COMPANY OF COLORADO
("COMPANY")

AND

[_____]
("SERVICE PROVIDER")



- [date] -

Table of Contents:

Contents

Article 1 - Rules of Interpretation 1

Article 2 - Definitions 2

Article 3 - Term and Termination 6

Article 4 - Service Provider's Obligations 8

Article 5 - Payment 12

Article 6 - Security for Performance 12

Article 7 - Default and Damages 15

Article 8 - Dispute Resolution 19

Article 9 - Representations and Warranties 20

Article 10 - Indemnification and Insurance 21

Article 11 - Miscellaneous 23

Exhibits:

EXHIBIT A NWA SERVICES
EXHIBIT B NWA SERVICES GUARANTEE
EXHIBIT C NWA SERVICES PAYMENT RATE
EXHIBIT D FORM OF LETTER OF CREDIT
EXHIBIT E FORM OF GUARANTY
EXHIBIT F NOTICES AND CONTACT INFORMATION

NON-WIRES ALTERNATIVE SERVICES AGREEMENT
BETWEEN
PUBLIC SERVICE COMPANY OF COLORADO
AND
[_____]

This Non-Wires Alternative Services Agreement (this "Agreement") is made this [_____] day of [_____, 20__], by and between (i) **Public Service Company of Colorado**, a Colorado corporation with a principal place of business at 1800 Larimer Street, Suite 1000, Denver, Colorado 80202 ("Company"), and (ii) [_____], a [state] [legal entity] with a principal place of business at [_____] ("Service Provider"). Company and Service Provider are hereinafter referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, the Colorado Public Utilities Commission ("CPUC") has required the Company, in certain circumstances, to conduct a technology-neutral competitive solicitation for Non-Wires Alternatives ("NWA") to defer, reduce, or avoid the costs of Major Distribution Grid Projects;

WHEREAS, the Company issued a technology-neutral request for proposals for Non-Wires Alternatives ("RFP");

WHEREAS, Service Provider desires to sell and deliver such Non-Wires Alternative Services ("NWA Services") as more fully described in Exhibit A – NWA Services attached to this Agreement, and Company desires to accept and receive such NWA Services on the terms and conditions set forth in this Agreement.

NOW THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

Article 1 - Rules of Interpretation

1.1 Interpretation.

(A) Capitalized terms listed in this Agreement shall have the meanings set forth in Article 2 - Definitions or as otherwise defined in this Agreement, whether in the singular or the plural or in the present or past tense. Words not otherwise defined in this Agreement shall (i) have meanings as commonly used in the English language, (ii) be given their generally accepted meaning consistent with Good Utility Practice, and (iii) be given their well-known and generally accepted technical or trade meanings.

(B) The following rules of interpretation shall apply: (i) references to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this Agreement except as the context may otherwise require; (ii) all Exhibits are incorporated into this Agreement (*provided*, *however*, that in the event of a conflict with the terms of this Agreement, the Agreement shall control); and (iii) use of the words "include" or

"including" or similar words shall be interpreted as "include without limitation" or "including, without limitation."

(C) None of the provisions of this Agreement shall be construed against one Party on the ground that such Party is the author of this Agreement or any part hereof.

1.2 Interpretation with Other Agreements. This Agreement does not modify the Parties' rights and obligations under any applicable Company rate schedule (if Service Provider is a customer of Company) or existing service agreement between the Parties. This Agreement does not provide Service Provider with authorization to interconnect or inject power into the Distribution Authority's System. Service Provider shall contract for any interconnection services in accordance with the applicable Distribution Tariff. Service Provider acknowledges that the Interconnection Agreement is/will be a separate contract and that (i) this Agreement is not binding on the Distribution Authority, (ii) this Agreement does not create any rights between Service Provider and the Distribution Authority nor any obligations on Distribution Authority to Service Provider with respect to this Agreement, and (iii) the Interconnection Agreement does not modify the Parties' rights and obligations under this Agreement. The applicable Distribution Authority shall be deemed to be a separate and unaffiliated contracting party for purposes of this Agreement, regardless whether such Distribution Authority is Company or an Affiliate of Company. To that end, any breach, dispute, or other issue related to the Distribution Authority's performance under any Interconnection Agreement or other conduct by the Distribution Authority related to the interconnection procedures and standards with respect to interconnection shall not be considered a breach by the Company of its obligation of good faith and fair dealing or any other statutory or common law requirement with respect to this Agreement and Service Provider waives any and all claims at equity or law related thereto. Likewise, any breach, dispute, or other issue related to the Company's performance of this Agreement or other conduct by Company related to this Agreement shall not be considered a breach by the Distribution Authority of its obligation of good faith and fair dealing or any other statutory or common law requirement under an Interconnection Agreement or the associated interconnection procedures and standards and Service Provider agrees to waive any and all claims at equity or law related thereto.

1.3 Good Faith and Fair Dealing. The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this Agreement. Unless expressly provided otherwise in this Agreement, (a) when this Agreement specifically references the consent, approval, or similar action by a Party, such consent or approval shall not be unreasonably withheld, conditioned or delayed, and (b) wherever this Agreement specifically gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be Commercially Reasonable.

Article 2 - Definitions

The following terms shall have the meanings set forth herein:

2.1 "Actual Damages" shall have the meaning provided in Section 7.3(B).

2.2 "Agreement" shall have the meaning set forth in the introductory paragraph.

2.3 "Applicable Law" means all laws, statutes, treaties, codes, ordinances, regulations, certificates, orders, licenses and permits of any Governmental Authority that are applicable to a Party, the business of a Party or the NWA Services, now in effect or hereafter enacted, including amendments to or interpretations of any of the foregoing by a Governmental Authority having jurisdiction, and all applicable judicial, administrative, arbitration and regulatory decrees, judgments, injunctions, writs, orders, awards or like actions.

2.4 "Business Day" means any Day that is not a Saturday, a Sunday, or a recognized holiday in the State of Colorado.

2.5 "Commercial Operation" shall mean that all equipment required for provision by Service Provider of the NWA Services shall have been installed, tested, and commissioned, that equipment and facilities, if any, necessary to connect with the Company's distribution grid have been installed, tested, and commissioned, that requirements of any applicable Interconnection Agreement(s) necessary for provision of NWA Services have been satisfied, and that the NWA Services are operational and capable of achieving the NWA Services Guarantee.

2.6 "Commercial Operation Year" shall have the meaning set forth in Section 4.1(G).

2.7 "Commercially Reasonable" or "Commercially Reasonable Efforts" means, with respect to any action to be taken or attempted by a Party under this Agreement, the level of effort in light of the facts known to such Party at the time a decision is made that: (a) can reasonably be expected to accomplish the desired action at a reasonable cost; (b) is consistent with Good Utility Practices; and (c) takes into consideration the amount of advance notice required to take such action, the duration and type of action and the competitive environment in which such action occurs.

2.8 "Company" shall have the meaning set forth in the introductory paragraph.

2.9 "CPUC" shall mean the Colorado Public Utilities Commission or any successor agency.

2.10 "CPUC Rules" shall mean the Colorado Public Utilities Commission's Rules Regulating Electric Utilities, codified at 4 Code of Colorado Regulations 723-3, as promulgated by the CPUC and amended from time to time. References in this Agreement to CPUC Rules shall include successor rules.

2.11 "Credit Rating" of any Person means the lowest rating assigned to such Person's long-term debt or deposit obligations (unenhanced by third-party support) by Standard & Poors and Moody's. If such Person has no outstanding long-term debt or deposit obligations, or if no rating is assigned to such obligations, "Credit Rating" shall mean the lowest general corporate credit rating or long-term issuer rating assigned to such Person by Standard & Poors or Moody's.

2.12 "Day" means a calendar day.

2.13 "Demand Reduction" shall mean a reduction in load, congestion, or other constraints at specified locations on the grid.

2.14 "Distribution Authority" means collectively those entities owning and/or operating the interconnected distribution system applicable to Service Provider pursuant to a Distribution Tariff, including (i) Company operating under and in accordance with its Distribution Tariff, and (ii) all entity(ies) responsible under the Interconnection Agreement for providing the distribution lines, any interconnection facilities and other equipment and facilities that interconnects at the Interconnection Point and distribution system.

2.15 "Distribution Authority's System" means the contiguously interconnected electric distribution facilities owned or operated by the Distribution Authority.

2.16 "Distribution Tariff" means the applicable tariff of the Distribution Authority, as amended from time to time.

2.17 "Effective Date" shall have the meaning set forth in Section 3.1.

2.18 "Event of Default" shall have the meaning set forth in Article 7.

2.19 "Good Utility Practices" means the practices, methods, standards and acts engaged in or approved by a significant portion of the applicable segment of the electric utility industry pertaining to services of the similar type and size to the NWA Services that, at a particular time, in the exercise of Commercially Reasonable judgment, in light of the facts that are known (or reasonably should have been known) at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with Applicable Law, permits, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy, and expedition. Good Utility Practices is not limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods, standards and acts generally acceptable or approved by a significant portion of the applicable segment of the electric power generation industry in the relevant region, during the relevant period.

2.20 "Governmental Authority" means any federal, state, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power; or any court or governmental tribunal.

2.21 "Guarantor" shall have the meaning set forth in Section 6.2(C).

2.22 "Interconnection Agreement" means the separate contract for interconnection to the Distribution Authority's System, as such agreement may be amended from time to time. For purposes of this Agreement, the Interconnection Agreement shall be interpreted to include any third party facility construction agreement or other agreement required by the Distribution Authority in accordance with the Distribution Tariff.

2.23 "Interconnection Point" means the physical point within the operational authority of the Distribution Authority at which electrical interconnection is made with the Distribution Authority's System in accordance with the Distribution Tariff and the Interconnection Agreement.

2.24 "Investment Grade" means a Credit Rating of both (a) Baa3 or higher by Moody's, and (b) BBB- or higher by Standard & Poors.

2.25 "kW" means kilowatt and "kWh" means kilowatt hour.

2.26 "Maintenance Schedule" is defined in Section 4.4(A).

2.27 "Major Distribution Grid Project" shall have the meaning set forth in CPUC Rules, Sec. 3527.

2.28 "Material Adverse Effect" means any effect (or effects taken together) that is materially adverse to the present or future business, operations, assets, liabilities, properties, results in operations or condition (financial or otherwise), prospects, or property of a Party, its business, or this Agreement.

2.29 "Metering Point" means the physical point at which Service Provider makes available and delivers to Company the NWA Services being provided by Service Provider to Company under this Agreement. The Metering Point is specified in Exhibit A –NWA Services.

2.30 "MW" means megawatt or one thousand kW and "MWh" means megawatt hours.

2.31 "Non-Wires Alternative" or "NWA" shall have the meaning set forth in CPUC Rules, Sec. 3527.

2.32 "NWA Services" shall refer to those services specified in Exhibit A.

2.33 "NWA Services Guarantee" shall have the meaning set forth in Section 4.2.

2.34 "NWA Services Guarantee Breach" shall have the meaning set forth in Section 7.2(A).

.

2.35 "Party" and "Parties" shall have the meanings set forth in the introductory paragraph.

2.36 "Peak Demand Event" shall have the meaning set forth in Exhibit B.

2.37 "PUC Approval" has the meaning set forth in Section 3.2(A)5.

2.38 "Required In-Service Date" is as defined in Section 4.1(C).

2.39 "Security Fund" shall have the meaning set forth in Section 6.1(A).

2.40 "Service Provider" shall have the meaning set forth in the introductory paragraph.

2.41 "Term" means the period of time during which this Agreement shall remain in full force and effect as further provided in Article 3.

Article 3 - Term and Termination

3.1 Term. This Agreement shall become effective as of the date of its execution ("Effective Date"), and shall remain in full force and effect until 11:59 pm on the last Day of the [insert] (X^{th}) Commercial Operation Year (the "Scheduled Termination Date"), subject to early termination as provided for in this Agreement.

3.2 Conditions Precedent.

(A) PUC Approval.

1. No later than forty-five (45) Days after the Effective Date, Company may apply to the CPUC for PUC Approval. If Company fails to apply for PUC Approval within forty-five (45) Days following the Effective Date, Company shall be deemed to have waived its right to obtain PUC Approval and to terminate this Agreement under this Section 3.2, and this Agreement shall remain in full force and effect thereafter.

2. If Company applies for PUC Approval, Company shall use Commercially Reasonable Efforts to obtain PUC Approval as soon as reasonably practicable. Seller shall cooperate with Company's efforts to obtain PUC Approval.

3. If Company applies for PUC Approval, Company shall have the right to terminate this Agreement, without any further financial or other obligation to Seller as a result of such termination, by notice to Seller

a. at any time within thirty (30) Days following issuance of a written order by the PUC rejecting PUC Approval, or granting PUC Approval with conditions unacceptable to Company in its sole discretion;

b. at any time between the two hundred fiftieth (250th) and two hundred eightieth (280th) Day] following Company's application for PUC Approval, if prior to the date of such termination the PUC has not issued a written order granting or rejecting PUC Approval;

c. at any time within thirty (30) Days following timely request for reconsideration (in whole or in any material part) by any third party with standing, of a written PUC order granting PUC Approval; and/or

d. at any time within thirty (30) Days following timely appeal by any party with standing, of a written PUC order granting PUC Approval.

4. If Company is eligible but fails to terminate this Agreement by the applicable date, Company shall be deemed to have waived its right to terminate this Agreement for that reason, and this Agreement shall remain in full force and effect thereafter.

5. For purposes of this Agreement, "PUC Approval" means a written order of the CPUC making an affirmative determination that all costs incurred under this Agreement are recoverable from Company's retail customers pursuant to Applicable Law, subject only to the requirement that the PUC retains ongoing prudency review of Company's performance and administration of this Agreement, as determined by Company in its sole discretion.

(B) Other Company CPs. [*if any*].

(C) Service Provider CPs. [if any - bid specific].

(D) Return of Security Fund.

Following a termination pursuant to Section 3.2(A) [or Section 3.2(B)] [or Section 3.2(C)], the Company will return to Seller the initial Security Fund within five (5) Business Days of such termination.

(E) The Service Provider must achieve Commercial Operations on or before the Required In-Service Date set forth in Section 4.1(C). Achievement of Commercial Operation by such date and PUC Approval pursuant to this Section 3.2 are conditions precedent for the Company's obligations set forth in this Agreement.

(F) Receipt by the Service Provider from applicable Governmental Authorities of all necessary permits, licenses, approvals, and authorizations necessary for approval of this Agreement and provision by Service Provider of the NWA Services is a condition precedent for the Company's obligations set forth in this Agreement.

3.3 Early Termination.

(A) Company may immediately terminate this Agreement upon written notice to Service Provider if Service Provider breaches any material obligation under this

Agreement and fails to cure such breach within fifteen (15) Days after receiving written notice of the breach. Service Provider must notify Company in writing upon curing the identified breach.

(B) Service Provider may request to terminate this Agreement by submitting written notice to the Company. The termination will be effective on the later of (i) the beginning of the calendar month that is immediately after the initial 12 month term, and (ii) the beginning of the calendar month that is closest to but at least thirty (30) Days after the Company received the notice. Upon delivery of a termination notice pursuant to this Section, Service Provider shall pay to Company by check or wire transfer of immediately available funds, a termination payment in an amount equal to the total amount payable by Company to Service Provider during the remaining term of this Agreement.

3.4 Effect of Termination. Applicable provisions of this Agreement shall continue in effect after termination to the extent necessary to (i) provide for final billings, payments and adjustments, (ii) enforce or complete the duties, obligations or responsibilities of the Parties under this Agreement, and (iii) address any remedies or indemnifications arising prior to termination.

Article 4 - Service Provider's Obligations

4.1 NWA Services. Service Provider shall deliver the NWA Services as described in Exhibit A –NWA Services during the Term of this Agreement.

(A) Service Provider shall procure all equipment and services necessary to fulfill its obligations under this Agreement. Service Provider must also provide to Company the ability to appropriately inform Service Provider when the NWA Services are required to be delivered.

(B) If necessary to provide the NWA Services, Service Provider shall be responsible for arranging, maintaining and paying the costs associated with the interconnection to the Distribution Authority's System, and shall comply with the Distribution Authority's requirements for interconnection and all requirements set forth in the applicable Distribution Tariff.

(C) Service Provider must cause the NWA Services to achieve Commercial Operation by [_____] ("the "Required In-Service Date")

(D) Service Provider shall notify Company of the date on which Service Provider believes Commercial Operation has been achieved (a "COD Notice"). A COD Notice shall include all necessary supporting documentation of the satisfaction or occurrence of all COD Conditions. Company shall have ten (10) Business Days to review a COD Notice and raise any Commercially Reasonable objection to Service Provider's satisfaction of any of the COD Conditions, *provided*, *however*, that Service Provider's COD Notice shall be deemed accepted by Company if Company fails to object within such time period. Service Provider may notify Company of completion of one or more COD Conditions on an individual and incremental basis prior to COD, *provided*, *however*,

that Company shall in all cases have up to ten (10) Business Days to review and object to each such notice.

(E) For purposes hereof, the "Commercial Operation Date" or "COD" means 12:01 am on the Day after which Service Provider's COD Notice has been accepted by Company or deemed accepted by Company pursuant to this Section.

(F) the "COD Conditions" are

1. an officer of Service Provider, authorized to bind Service Provider and who is familiar with the NWA Services, has confirmed in writing that:

a. all necessary and material permits have been obtained, are in full force and effect and the entity granting the permit has not placed any temporary or conditional restrictions or limitations on the Service Provider's ability to provide the NWA Services in conformance with the terms of this Agreement,

b. Seller is in compliance with this Agreement in all material respects,

c. the NWA Services are available to be provided in accordance with Service Provider's operating agreements, contracts, and manufacturers' warranties,

d. Service Provider has proven to Company's reasonable satisfaction that

i. Service Provider and the Distribution Authority have executed the Interconnection Agreement, if any, and Service Provider has received no notice of breach thereof from the Distribution Authority,

ii. Service Provider has or is capable of declaring commercial operation under the Interconnection Agreement, if any, and

iii. Seller has made all other arrangements necessary to deliver the NWA Services during the Term;

e. Seller has executed and delivered to Company all Security Fund documents or instruments required under Article 6.

(G) For purposes hereof, the first "Commercial Operation Year" shall mean the period starting at 12:01 a.m. on January 1st following the Commercial Operation Date and ending at 11:59 pm on the last Day of such calendar year, and each successive "Commercial Operation Year" shall mean the 12-month period following the prior Commercial Operation Year.

1. If necessary to provide the NWA Services, Service Provider shall be responsible for arranging, maintaining and paying the costs associated with the

interconnection to the Distribution Authority's System, if any, and shall comply with the Distribution Authority's requirements for interconnection and all requirements set forth in the applicable Distribution Tariff, to the extent required for the provision of the NWA Services.

4.2 NWA Services Guarantee.

(A) Service Provider guarantees that the NWA Services provided for in Exhibit A –NWA Services will, when installed: (1) achieve at least ninety percent (90%) of the kW of Demand Reduction provided for in Exhibit A –NWA Services during a peak demand event for the specified duration; (2) provide such Demand Reduction at the portion(s) of the distribution grid specified in Exhibit A –NWA Services; and (3) be operationally available by the Required In-Service Date (the foregoing clauses (1) through (3) being collectively referred to herein as the "NWA Services Guarantee"). The NWA Services Guarantee also encompasses the guarantees set forth in Exhibit B.

(B) Service Provider guarantees that it can and will achieve the NWA Services Guarantee when the Company declares a peak demand event applicable to the Service Provider's NWA Services.

(C) Service Provider's receipt of Payments under this Agreement is conditioned upon the truth and accuracy of its NWA Services Guarantee and the performance of its obligations hereunder.

4.3 Measurement and Verification.

(A) The kW Demand Reduction delivered by Service Provider will be measured at the Metering Point by the Company or a third-party contractor selected and retained by the Company. Service Provider shall fund the cost of any additional advanced metering equipment that the Company determines, in its sole discretion, is necessary to measure and verify the NWA Services provided.

(B) In lieu of Section 4.3(A) above, and if deemed appropriate by mutual agreement of the Parties, the measurement and verification protocols to measure Demand Reduction for the NWA Services that may be established in a measurement and verification plan ("M&V Plan"). The M&V Plan will include, among other things, witness testing and appropriate verification.

(C) Payment to Service Provider for the NWA Services pursuant to Article 5 is dependent upon measurement and verification. Performance data of the NWA Services will be reviewed and verified as established in the M&V Plan or measurement pursuant to (A) above before Payment is remitted to Service Provider. Company shall have full rights to audit the books and records of Service Provider to determine compliance with this Agreement and the NWA Services Guarantee.

(D) Service Provider shall provide annual reports to the Company regarding whether and to what extent the NWA Services produce benefits to disproportionally impacted communities. The annual reports shall compare realized

benefits to any predicted benefits presented to the Company prior to entry into this Agreement and shall discuss the reasons for any shortfall in actual benefits as compared to previously predicted benefits.

4.4 Operations and Maintenance. Service Provider shall maintain any facilities necessary to deliver the NWA Services in accordance with Good Utility Practices. Such maintenance shall include replacement or repair, whichever is appropriate under Good Utility Practices, of degraded or damaged equipment, and other such other maintenance as is necessary to continue to reliably deliver the NWA Services.

(A) Service Provider shall provide the Company with a schedule of the expected Scheduled Outages for the NWA Services for the first year following the Effective Date ("Maintenance Schedule"), including the start time and expected duration of the outage. Service Provider shall update the Maintenance Schedule annually. Absent the prior written consent of the Company, Service Provider shall schedule all its outages during the months of October and November.

(B) Service Provider shall maintain an accurate and up-to-date record of every time the NWA Services are dispatched by the Company, and shall deliver such information to the Company within five (5) Business Days after the end of any month in which the NWA Services are dispatched.

(C) Representatives of Company shall have access to any facilities necessary to deliver the NWA Services from time to time, on Commercially Reasonable prior notice, to read and/or test meters, perform inspections and take such other actions as may be appropriate to facilitate Company's performance under this Agreement.

(D) Service Provider may indicate that certain information and data to which the Company is given access is confidential and certain other information may be confidential pursuant to applicable data privacy laws ("Confidential Information"). Regardless of the confidentiality, all such Confidential Information may be subject to: 1) state and federal freedom of information and open records act laws; 2) review by the appropriate state jurisdiction; 3) any other governmental authority or judicial body with jurisdiction relating to these matters; and 4) legal and regulatory discovery. Under such circumstances, the Company shall notify the Service Provider regarding such circumstances to allow it to seek a protective order, as appropriate, or otherwise prevent the disclosure of the Confidential Information, as legally permitted. The Company shall make all reasonable efforts to preserve the confidentiality of the Confidential Information, but Service Provider and the Company acknowledge that such treatment is neither automatic nor guaranteed. The Company and Respondent also specifically anticipate that Confidential Information may be filed with the CPUC and agree to such disclosure provided the filing party seeks an appropriate protective order.

4.5 Removal of Equipment. Service Provider agrees that any and all project-related removal and disposal of equipment or materials, including disposal because equipment, facilities, or materials have reached the end of useful life and/or as a result of

a termination of this Agreement, will be conducted at its sole cost and expense and in accordance with all applicable laws, rules, and regulations.

Article 5 - Payment

5.1 Payment to Service Provider. The Company will pay Service Provider for the NWA Services rendered under this Agreement as follows.

(A) In exchange for being available to provide the NWA Services Guarantee during Peak Demand Events, the Company will make Payments to Service Provider as set forth in Exhibit A –NWA Services.

(B) Subject to the other applicable provisions of this Agreement, Company will make each annual NWA Services Payment in a single lump sum on the last day of each Commercial Operation Year during the Term of this Agreement, *provided*, that the Company will only make Payments if (1) the Service Provider performed during Peak Demand Events during the applicable Commercial Operation Year, and (2) the Demand Reduction provided by Service Provider was verified as provided in this Agreement.

Article 6 - Security for Performance

6.1 Security Fund.

(A) During the Term of this Agreement, Service Provider shall fund and maintain security in favor of Company, at Service Provider's expense, to secure Service Provider's obligations to Company under this Agreement (the "Security Fund"), in accordance with this Article 6.

(B) Service Provider shall establish and fund the initial Security Fund in the amount of no less than the Total Contract Value defined as the sum of all yearly payments set forth in Exhibit C –NWA Services Payment Rate, for the Term, no later than thirty (30) Days following the Effective Date.

(C) Company may draw from the Security Fund such amounts as are necessary to recover amounts owing to Company pursuant to this Agreement, including but not limited to any Penalties, Actual Damages, or any amounts for which Company is entitled to indemnification under this Agreement. Company may, in its sole discretion, draw all or any part of such amounts from any form of security to the extent available pursuant to this Article 6 and in any sequence Company may select. Company's failure or delay to draw any amount from the Security Fund in any instance shall not prejudice Company's rights to subsequently recover such amount from the Security Fund or in any other manner.

(D) Company shall notify Service Provider within five (5) Business Days following any draw on the Security Fund by Company, including the amount thereof and the basis therefor.

6.2 Form.

(A) The Security Fund may be in the form of an irrevocable standby letter of credit substantially in the form of Exhibit D - Form of Letter of Credit (a "Letter of Credit") from a financial institution acceptable to Company ("Issuer").

1. The Issuer of the Letter of Credit shall have and maintain a Credit Rating equivalent to A- (or better) by Standard & Poors and A3 (or better) from Moodys. If such Credit Rating is A- or A3, the Issuer must not be on credit watch by any rating agency.

2. The Letter of Credit must be for a minimum term of three hundred sixty (360) Days. Service Provider shall give Company at least thirty (30) Days advance notice prior to any expiration or earlier termination of the Letter of Credit. Service Provider shall cause the renewal or extension of the Letter of Credit for additional consecutive terms of three hundred sixty (360) Days or more (or, if shorter, the remainder of the Term) more than 30 Days prior to each expiration date of the security. If the Letter of Credit is not renewed or extended at least thirty (30) Days prior to its expiration date or otherwise is terminated early, Company shall have the right to draw immediately upon the Letter of Credit and to place the amounts so drawn, at Service Provider's cost and with Service Provider's funds, in an Escrow Account in accordance with paragraph (B) below, until and unless Service Provider provides a substitute form of security meeting the requirements of this Section 6.2.

(B) The Security Fund may be in the form of U.S. currency deposited into an escrow account with a state- or federally-chartered commercial bank with an office in the State of Colorado, with net assets of at least $1 billion (the "Escrow Account").

1. The Escrow Account shall be governed by an escrow and account control agreement in form mutually satisfactory to Service Provider, Company and the escrow agent, provided that (a) Company shall hold a first and exclusive perfected security interest in the funds in the Escrow Account, (b) Company shall be permitted unilaterally to draw down any amount therein, regardless of any protest by Service Provider or any other party liable thereon (*provided* that nothing in the Escrow Agreement shall preclude any protest against Company by Service Provider, following any draw, that such draw did not comply with this Agreement), and (c) Service Provider shall pay all fees and expenses of the escrow agent.

2. Funds held in the Escrow Account may be invested as Service Provider may direct in any of the following:

- a money-market fund sponsored by the escrow agent;
- U.S. treasury obligations with a maturity of ninety (90) Days or less;

- commercial paper rated "A" or better, with a maturity of ninety (90) Days or less; or

- other liquid investment-grade investments with maturities of three months or less, approved by Company in advance (such approval not to be unreasonably withheld or delayed).

3. All investment income on the Escrow Account shall be taxable to, and accrue for the benefit of, Service Provider. After the Commercial Operation Date, periodic sweeps by Service Provider for recovery of interest earned by the escrowed funds shall be allowed, and if at any time the balance in the Escrow Account exceeds the required amount of security, the escrow agent may remit the excess to Service Provider.

(C) The Security Fund may consist of a guaranty substantially in the form of Exhibit E – Form of Guaranty, from a parent or other guarantor ("Guarantor") with a minimum of net worth of at least $250,000,000 and an Investment Grade Credit Rating (and if such Credit Rating is exactly equivalent to BBB- [Standard & Poors] / Baa3 [Moody's], the Guarantor must not be on credit watch by any rating agency). If the Credit Rating of the Guarantor is downgraded below Investment Grade, put on credit watch, or an event occurs that (in the reasonable determination of Company) portends a Material Adverse Effect in the creditworthiness of the Guarantor, then Company may require Service Provider to convert the guaranty to a Security Fund instrument meeting the criteria set forth in either paragraph (A) or paragraph (B) above no later than ten (10) Days after notice from Company.

(D) Company shall negotiate in good faith any needed escrow and account control agreement and, upon request by Service Provider, immaterial changes to Exhibit D – Form of Letter of Credit and/or Exhibit E – Form of Guaranty, provided that Service Provider shall pay or reimburse Company for the direct expenses (including the fees and expenses of counsel) incurred by Company in connection therewith.

(E) Service Provider may change the form of the Security Fund at any time and from time to time upon Commercially Reasonable prior notice to Company, provided, however, that the Security Fund must at all times satisfy the requirements of this Article 6.

6.3 Replacement. In the event that the Security Fund ever fails to comply with the requirements of this Article 6 or Company determines in a Commercially Reasonable manner that an event has occurred or circumstances have developed that threaten to cause the Security Fund to fail to comply with the requirements of this Article 6 (e.g., a Guarantor is placed on negative credit watch by a rating agency), Service Provider shall be required to replace the Security Fund with security in compliance with this Article 6 within five (5) Days following notice thereof from Company.

6.4 Survival. The Security Fund shall survive termination of this Agreement to be available to pay any amounts owed to Company arising prior to or upon termination.

Company may draw such amounts and shall release the balance of the Security Fund (including any accumulated interest, if applicable) to Service Provider.

6.5 Expenses. Service Provider shall reimburse Company for its direct expenses (including the fees and expenses of counsel) incurred by Company in connection with the preparation, negotiation, execution and/or release (including making a draw of funds) of the Security Fund under this Article 6.

Article 7 - Default and Damages

7.1 Default by Service Provider: General.

(A) *Events*. Any of the following events shall constitute a default by under this Agreement. If no cure period is provided below, such default shall be deemed an Event of Default by Service Provider immediately upon its occurrence. If a cure period is provided below, such default shall mature into an Event of Default if not cured within the indicated cure period.

1. Service Provider's application for, or consent (by admission of material allegations of a petition or otherwise) to, the appointment of a receiver, trustee or liquidator for Service Provider or for all or substantially all of its assets, or its authorization of such application or consent, or the commencement of any proceedings seeking such appointment without such authorization, consent or application, which proceedings continue undismissed or unstayed for a period of sixty (60) Days from inception.

Cure Period: None.

2. Service Provider's authorization or filing of a voluntary petition in bankruptcy or application for or consent (by admission of material allegations of a petition or otherwise) to the application of any bankruptcy, reorganization, readjustment of debt, insolvency, dissolution, liquidation or other similar law of any jurisdiction or the institution of such proceedings against Service Provider without such authorization, application or consent, which proceedings remain undismissed or unstayed for sixty (60) Days from its inception or which result in adjudication of bankruptcy or insolvency within such time.

Cure Period: None.

3. Service Provider's assignment of this Agreement not permitted by Section 11.2.

Cure Period: None.

4. Any representation or warranty by Service Provider in this Agreement that has a Material Adverse Effect on Service Provider's ability to perform this Agreement is proven to have been false in any material respect when made.

Cure Period: None.

5. Service Provider's failure to establish and, once established, maintain the Security Fund as and in the amounts required under Article 6.

Cure Period: Five (5) Business Days after Company provides notice of Service Provider's failure.

6. Service Provider's failure to obtain and maintain insurance in scope and amounts required under Article 10.

Cure Period: Five (5) Business Days after Company provides notice of Service Provider's failure.

7. Service Provider's failure to make any payment to Company as and when required by this Agreement, including Liquidated Damages, Actual Damages, and any required indemnification.

Cure Period: Ten (10) Business Days after Company provides notice that the amount is overdue.

8. Any representation or warranty by Service Provider in this Agreement that has a Material Adverse Effect on Service Provider's ability to perform this Agreement ceases to remain true during the Term, other than due to a change of law.

Cure Period: None.

9. Subject to Section 7.2, failure for Services Provider to deliver the NWA Services when called upon

Cure Period: None.

10. If, at any time during the Term of this Agreement the Company learns that the equipment necessary to deliver the NWA Services was not actually or properly installed, or no longer meets the NWA Services Guarantee,

Cure Period: None.

11. The breach by Service Provider of the Interconnection Agreement, if any, which breach (i) materially interferes with Service Provider's delivery of the NWA Services or Company's ability to accept or receive such NWA Services, and/or (ii) otherwise has a Material Adverse Effect on Company.

Cure Period: Thirty (30) Days from the breach or the cure period allowed by the Interconnection Agreement (whichever is longer)

(B) *Remedies for Default*. In connection with any default by Service Provider under this Section 7.1(whether or not cured by Service Provider, Company may:

1. Subject to Section 7.2, obtain Liquidated Damages as provided for in this Agreement; and,

2. Seek Actual Damages in such amounts and on such basis for the default as authorized by this Agreement; and,

3. Offset against any payments due to Service Provider, any Actual Damages and other amounts due from Service Provider; and

4. Draw any Liquidated and Actual Damages and other amounts due from Service Provider, from the Security Fund.

(C) *Termination for Event of Default*. Upon and at any time following an Event of Default by Service Provider under this Section 7.1, in addition to its rights under Section 7.1 above, Company may terminate this Agreement immediately upon notice to Service Provider, without penalty or further obligation to Service Provider. In connection with any such termination, Company may collect from Seller all Actual Damages arising from such Event of Default through the Scheduled Termination Date.

7.2 Service Provider's Default for Underperformance and Non-Performance. Service Provider acknowledges that Company's agreement to make Payment to Service Provider is contingent upon the truth and accuracy of Service Provider's NWA Services Guarantee, its other representations and warranties herein, and the performance by Service Provider of its obligations hereunder. The Parties acknowledge and agree that the amount of damages that Company would suffer as a result of a NWA Services Guarantee Breach would be substantial but difficult or impossible to determine, that otherwise obtaining an adequate remedy is inconvenient due, among other things, to the timeframes and processes associated with planning and constructing electric distribution infrastructure, and that the Liquidated Damages constitute a reasonable approximation of the harm or loss. The Parties further acknowledge and agree that the Liquidated Damages provided for herein are not punitive nor in the nature of a penalty.

(A) Upon Service Provider's first failure to achieve at least ninety percent (90%) of the Demand Reduction for the required duration as provided in Exhibit A –NWA Services during a Peak Demand Event ("NWA Services Guarantee Breach"), then Service Provider will be obligated (without limiting Company's other rights and remedies under this Agreement, at law or in equity), immediately upon the occurrence of such NWA Services Guarantee Breach, to pay to Company by check or wire transfer of immediately available funds the applicable Liquidated Damages equal to the total amount payable by Company to Service Provider for the Commercial Operation Year in which the first NWA Services Guarantee Breach occurred, which amount the Parties agree is specifically intended to be a Liquidated Damages amount and not a penalty.

(B) Upon Service Provider's second NWA Services Guarantee Breach, Company shall be entitled to terminate this Agreement in whole or in part, effective upon

notice, and shall be relieved of any responsibility to make any further Payments (Service Provider hereby releasing and forever discharging the Company from any and all losses, liabilities, claims, costs and expenses resulting from Service Provider's failure to receive such incentive payments in accordance with the foregoing).

7.3 Default by Company: General.

(A) *Events*. Any of the following events shall constitute a default under this Agreement. If no cure period is provided below, such default shall be deemed an Event of Default by Company immediately upon its occurrence. If a cure period is provided below, such default shall mature into an Event of Default if not cured within the indicated cure period.

1. Company's application for, or consent (by admission of material allegations of a petition or otherwise) to, the appointment of a receiver, trustee or liquidator for Company or for all or substantially all of its assets, or its authorization of such application or consent, or the commencement of any proceedings seeking such appointment without such authorization, consent or application, which proceedings continue undismissed or unstayed for a period of sixty (60) Days from inception.

Cure Period: None.

2. Company's authorization or filing of a voluntary petition in bankruptcy or application for or consent (by admission of material allegations of a petition or otherwise) to the application of any bankruptcy, reorganization, readjustment of debt, insolvency, dissolution, liquidation or other similar law of any jurisdiction or the institution of such proceedings against Company without such authorization, application or consent, which proceedings remain undismissed or unstayed for sixty (60) Days from its inception or which result in adjudication of bankruptcy or insolvency within such time.

Cure Period: None.

3. Company's assignment of this Agreement not permitted by Section 11.2.

Cure Period: None.

4. Any representation or warranty by Company in this Agreement that has a Material Adverse Effect on Company's ability to perform this Agreement is proven to have been false in any material respect when made.

Cure Period: None.

5. Company's failure to make any payment to Service Provider as and when required by this Agreement, including Actual Damages, and any required indemnification.

Cure Period: Ten (10) Business Days after Service provider provides notice that the amount is overdue.

6. Any representation or warranty by Company in this Agreement that has a Material Adverse Effect on Company's ability to perform this Agreement ceases to remain true during the Term, other than due to a change of law.

(B) The Parties confirm that the express remedies and measures of damages provided in this Agreement satisfy the essential purposes hereof. If no remedy or measure of damages is expressly herein provided, the obligor's liability shall be limited to all direct damages proximately caused by such default ("Actual Damages") incurred by the non-defaulting Party. **Neither Party shall be liable to the other Party for consequential, incidental, punitive, exemplary, special, treble, equitable or indirect damages, regardless of whether the relevant cause of action arises from statute, tort or contract** (except to the extent expressly provided herein); *provided*, *however*, that if either Party is held liable to a third party for such damages and the Party held liable for such damages is entitled to indemnification from the other Party hereto, the indemnifying Party shall be liable for, and obligated to reimburse the indemnified Party for all such damages.

(C) To the extent damages required to be paid hereunder are liquidated, the Parties acknowledge that actual damages would be substantial but difficult or impossible to determine, that otherwise obtaining an adequate remedy is inconvenient, and that the liquidated damages constitute a reasonable approximation of the harm or loss.

7.4 Cumulative Remedies. Except as explicitly provided to the contrary in this Agreement, each right or remedy of the Parties provided for in this Agreement shall be cumulative of and shall be in addition to every other right or remedy provided for in this Agreement, and the exercise of one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any other rights or remedies provided for herein.

7.5 Duty to Mitigate. Each Party shall use Commercially Reasonable Efforts to mitigate any damages it may incur as a result of a default by the other Party under this Agreement.

Article 8 - Dispute Resolution

8.1 Disputes. The Company will have sole discretion to determine the final resolution of any and all issues pertaining to this Agreement, including, but not limited to, project eligibility, energy savings, peak Demand Reduction, and Payment amounts payable.

8.2 Governing Law. The interpretation and performance of this Agreement, and all actions related hereto (whether sounding in contract, tort or otherwise), shall be governed and construed in accordance with the laws of the State of Colorado, exclusive of conflict of laws principles.

8.3 Venue. The Parties submit to the exclusive jurisdiction of the state courts of the State of Colorado for purposes of resolving any dispute hereunder. Venue for any court proceedings shall lie exclusively in the Colorado District Court for the City and County of Denver or, if jurisdictionally available, the U.S. District Court for the District of Colorado.

8.4 Waiver of Jury Trial. **Service Provider and Company each hereby knowingly, voluntarily and intentionally waive any rights they may have to a trial by jury** in respect of any litigation based hereon, or arising out of, under, or in connection with, this Agreement or any course of conduct, course of dealing, statements (whether oral or written) or actions of Service Provider and Company related hereto and expressly agree to have any disputes be adjudicated by a judge of the court having jurisdiction, without a jury.

Article 9 - Representations and Warranties

9.1 Each Party hereby represents and warrants to the other as follows, which representations and warranties shall be deemed to be repeated, if applicable, by each Party throughout the Term:

(A) Such Party is a valid separate legal entity, duly organized, validly existing and in good standing under Applicable Law. It is qualified to do business in the State of Colorado and it has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this Agreement.

(B) The Party's execution, delivery, and performance of all of its obligations under this Agreement have been duly authorized by all necessary organizational action, and do not and will not:

1. require any consent or approval by any governing corporate or management body, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to the other Party upon its request);

2. violate any Applicable Law, the violation of which could have a Material Adverse Effect on the representing Party's ability to perform its obligations under this Agreement;

3. result in a breach or constitute a default under the representing Party's formation documents, bylaws or equivalent, or under any agreement relating to its management or affairs or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which it is a party or by which it or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a Material Adverse Effect on the representing Party's ability to perform its obligations under this Agreement; or

4. result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature

upon or with respect to any of the assets or properties of the representing Party now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a Material Adverse Effect on the representing Party's ability to perform its obligations under this Agreement.

(C) This Agreement is a valid and binding obligation of the representing Party.

(D) The execution and performance of this Agreement will not conflict with or constitute a breach or default under any contract or agreement of any kind to which the representing Party is a party or any judgment, order, or Applicable Law, applicable to it or its business.

Article 10 - Indemnification and Insurance

10.1 Indemnification.

(A) To the fullest extent permitted by law, Service Provider shall indemnify, defend and hold harmless Company, and its parent company, subsidiaries, affiliates and their respective shareholders, officers, directors, employees, agents, representatives, successors and assigns (collectively, the "Indemnified Parties"), from and against any and all claims, actions, suits, proceedings, losses, liabilities, penalties, fines, damages, costs or expenses, including without limitation reasonable attorneys' fees ("Claim"), resulting from (a) any breach of the representations, warranties, covenants and obligations of Service Provider under this Agreement, (b) any act or omission of Service Provider, whether based upon Service Provider's negligence, strict liability or otherwise, in connection with the performance of this Agreement, or (c) any third party claims of any kind, whether based upon negligence, strict liability or otherwise, arising out of or connected in any way to Service Provider's performance or nonperformance under this Agreement.

(B) If any Claim is brought against the Indemnified Parties, Service Provider shall assume the defense of such Claim, with counsel reasonably acceptable to the Indemnified Parties, unless in the opinion of counsel for the Indemnified Parties a conflict of interest between the Indemnified Parties and Service Provider may exist with respect to such Claim. If a conflict precludes Service Provider from assuming the defense, then Service Provider shall reimburse the Indemnified Parties on a monthly basis for the Indemnified Parties' reasonable defense costs through separate counsel of the Indemnified Parties' choice. If Service Provider assumes the defense of the Indemnified Parties with acceptable counsel, the Indemnified Parties, at their sole option and expense, may participate in the defense with counsel of their own choice without relieving Service Provider of any of its obligations hereunder.

(C) Service Provider's obligation to indemnify the Indemnified Parties shall survive the expiration or termination of this Agreement.

10.2 Insurance.

(A) Service Provider shall maintain during the term of this Agreement, at its own expense, employers' liability and workers' compensation insurance providing benefits in accordance with the laws and regulations of the State of Colorado.

(B) Service Provider shall maintain, during the term of the Agreement, at its own expense commercial general liability insurance, including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

(C) Service Provider shall maintain, during the term of the Agreement, at its own expense comprehensive automobile liability insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

(D) Service Provider shall maintain, during the term of the Agreement, at its own expense excess public liability insurance over and above the employers' liability, commercial general liability, and comprehensive automobile liability insurance coverage, with a minimum combined single limit of Ten Million Dollars ($10,000,000) per occurrence/Ten Million Dollars ($10,000,000) aggregate.

(E) The insurance required by this Section 10.2 shall, by endorsement to the policy or policies, provide for thirty (30) Days' written notice to Public Service prior to cancellation, termination, alteration, or material change of such insurance.

(F) The commercial general liability insurance, comprehensive automobile Insurance and excess public liability insurance policies shall name the Company, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees as additional insureds.

(G) The commercial general liability insurance, comprehensive automobile liability insurance, and excess public liability insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies or self-insurance maintained by Public Service.

(H) The commercial general liability insurance, comprehensive automobile liability insurance, and excess public liability insurance policies, if written on a claims first made basis, shall be maintained in full force and effect for two (2) years after termination of this Agreement, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Company.

(I) The requirements contained herein as to the types and limits of all insurance to be maintained are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Service Provider.

(J) Evidence of the insurance required in this Section 10.2 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by Public Service.

(K) If Service Provider is self-insured with an established record of self-insurance, the Customer may comply with the following in lieu of Section 10.2 (B) – (L):

1. Service Provider shall provide to Public Service, at least thirty (30) days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under Section 10.2(B) – (D).

2. If Service Prover ceases to self-insure to the level required hereunder, or if the Service Provider is unable to provide continuing evidence of its ability to self-insure, Service Provider agrees to immediately obtain the coverage required under Section 10.2(B) – (L).

(L) Service Provider shall provide Public Service certificates of insurance evidencing the requisite coverage and provisions prior to the Required In-Service Date. Afterwards, Public Service may periodically request proof of current insurance coverage in order to verify compliance with the requirements of this Section 10.2. Upon receipt of any such request, the Service Provider shall provide certificates of insurance evidencing the requisite coverage and provisions. Failure of Service Provider to provide timely evidence of proper insurance shall constitute a material breach and may result in termination of this Agreement pursuant to Section 3.3.

(M) Failure of Service Provider or Public Service to enforce or maintain the minimum levels of insurance does not relieve Service Provider from its obligation to maintain such levels of insurance or relieve Service Provider of any liability.

(N) The Parties agree to promptly notify each other, in writing, of any personal injury or damage to property apparently or actually related to the provision of services pursuant to this Agreement.

Article 11 - Miscellaneous

11.1 Notices.

(A) For coordination purposes, any notice or other communication (but not including invoices or routine correspondence relating to performance by Service Provider) given under this Agreement to any party must be in writing and must be sent by hand or overnight mail service, or registered or certified United States mail, return receipt requested, to the attention of the other Party at the addresses noted in Exhibit F – Notices and Contact Information.

(B) The Parties recognize the need for accurate communications between them. Each Party consents to the recording of telephone conversations between their employees and representatives, related to the performance and administration of this Agreement.

11.2 Non-Assignment. Neither this Agreement, nor any part or the whole of any project arising hereunder, and to include no part or the whole of any work associated with any project, may be assigned, delegated, subcontracted, or otherwise transferred by Service Provider without the prior written approval of the Company in each case. Service Provider shall give Company at least ninety (90) Days' notice for any planned assignment of this Agreement or a project arising hereunder.

11.3 Severability. In the event any of the terms, covenants, or conditions of this Agreement, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of the Agreement and their application not adversely affected thereby shall remain in force and effect; *provided*, *however*, that Company and Service Provider shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this Agreement with a view toward effecting the purposes of this Agreement by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

11.4 Complete Agreement; Amendments. The terms and provisions contained in this Agreement constitute the entire agreement between Company and Service Provider with respect to the NWA Services and shall supersede all previous communications, representations, or agreements, either verbal or written, between Company and Service Provider with respect to the NWA Services. Any amendment of this Agreement, or any waiver of any provision hereof, shall be evidenced by a writing signed by the Parties to be bound thereby.

11.5 Waiver. The failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this Agreement, or to take advantage of any of its rights hereunder, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

11.6 Headings. Captions and headings used in this Agreement are for ease of reference only and do not constitute a part of this Agreement.

11.7 Counterparts. This Agreement may be executed in counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

11.8 Exhibits. Either Party may change the information in Exhibit F – Notices and Contact Information at any time by notice without the approval of the other Party. All

other Exhibits may be changed to the extent allowed by specific provisions of this Agreement or with the mutual consent of both Parties.

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the date first set forth above.

Service Provider:

By: _____

Company:

Public Service Company of Colorado

By: _____

EXHIBIT A

NWA SERVICES

(All sections of this form must be completed and attached to a fully executed Non-Wires Alternative Services Agreement)

Service Provider Information

Name of Service Provider _____

Mailing Address _____

(Street number and name) (Suite number)

_____

(City, state, zip code)

Nature of Business _____

Contact Person _____ Title _____

Email _____ Phone _____

Non-Wires Alternative Services Details

Project Name _____

Project Site Location _____

NWA Location _____

Metering Point _____

NWA Category: *(check all that apply)*

☐Demand Response ☐Energy Efficiency ☐Energy Storage

☐Distributed Generation ☐Other (*describe in Summary*)

NWA Services Provided _____

Proposed NWA Services Summary _____

Methodology for Calling on NWA Services (if applicable)

EXHIBIT B

NWA SERVICES GUARANTEE

[To be inserted]

EXHIBIT C

NWA SERVICES PAYMENT RATE

NWA Services Payment Rate

In exchange for the NWA Services described above, and subject to the terms and conditions set forth in the Agreement, the Company agrees to pay Service Provider the following in each Commercial Operation Year of the Agreement, beginning in the Commercial Operation Year in which the Required In-Service Date occurs:

Required In-Service Date _____

Commercial Operation Year

1 $_____

2 $_____

3 $_____

4 $_____

5 $_____

EXHIBIT D

FORM OF LETTER OF CREDIT

[LETTERHEAD OF ISSUING BANK]

Irrevocable Standby Letter of Credit No: _____	Date of Issuance: _____
Beneficiary: [Public Service Company of Colorado]	Initial Expiration Date: [Must be at least one year after date of issuance]
	Applicant:

As the Issuing Bank ("Issuer"), we, [Name of Issuing Bank], hereby establish this irrevocable Standby Letter of Credit No. ____ (this "Letter of Credit") in favor of the above-named beneficiary ("Beneficiary") for the account of the above-named applicant ("Applicant") in the amount of US$ _____ (_____ Million U.S. Dollars).

Beneficiary may draw all or any portion of this Letter of Credit at any time and from time to time, and Issuer will make funds immediately available to Beneficiary upon presentation of Beneficiary's draft(s) at sight in substantially the form attached hereto as Exhibit "A" ("Sight Draft"), drawn on Issuer and accompanied by this Letter of Credit. All Sight Drafts must be signed on behalf of Beneficiary, and the signator must indicate his or her title or other official capacity. No other documents will be required to be presented. Issuer will effect payment under this Letter of Credit within twenty-four (24) hours after presentment of any Sight Draft. Payment shall be made in U.S. Dollars with Issuer's own funds in immediately available funds.

Issuer will honor any Sight Draft presented in substantial compliance with the terms of this Letter of Credit at the Issuer's letterhead office, the office located at _____ or any other full service office of the Issuer on or before the above-stated expiration date, as such expiration date may be extended hereunder. Partial and multiple draws and presentations are permitted on any number of occasions. Following any partial draw, Issuer will endorse this Letter of Credit and return the original to Beneficiary.

This Letter of Credit is issued pursuant to the provisions of that certain Non-Wires Alternative Services Agreement between Beneficiary and Applicant dated as of _____, 20___ (as the same may have been or may be amended from time to time, the "Agreement"). Notwithstanding any reference in this Letter of Credit to the Agreement or any other documents, instruments or agreements, or references in the Agreement or any other documents, instruments or agreements to this Letter of Credit, this Letter of Credit contains the entire agreement between Beneficiary and Issuer relating to the obligations of Issuer hereunder.

This Letter of Credit will be automatically extended each year without amendment for a period of one (1) year from the expiration date hereof, as extended, unless at least thirty (30) days prior to the expiration date, Issuer notifies Beneficiary by registered or certified

mail that it elects not to extend this Letter of Credit for such additional period. Notice of non-extension will be given by Issuer to Beneficiary at Beneficiary's address set forth herein or at such other address as Beneficiary may designate to Issuer in writing at Issuer's letterhead address.

This Letter of Credit is freely transferable by Beneficiary in whole or in part, and the number of transfers is unlimited. Issuer shall effect any transfers immediately upon presentation to Issuer of this Letter of Credit and a completed written transfer request substantially in the form attached hereto as Exhibit "B." Such transfer will be effected at no cost to Beneficiary. Any transfer fees assessed by Issuer will be payable solely by Applicant, and the payment of any transfer fees will not be a condition to the validity or effectiveness of the transfer of this Letter of Credit.

Issuer waives any rights it may have, at law or otherwise, to subrogate to any claims which Beneficiary may have against Applicant or Applicant may have against Beneficiary.

This Letter of Credit is subject to the uniform customs and practice for documentary credits (2007 Revision), International Chamber of Commerce publication No. 600 (the "UCP"), except to the extent that the terms hereof are inconsistent with the provisions of the UCP, including but not limited to Articles 14(b) and 36 of the UCP, in which case the terms of this Letter of Credit shall govern. With respect to Article 14(b) of the UCP, Issuer shall have a reasonable amount of time, not to exceed three (3) banking days following the date of Issuer's receipt of documents from Beneficiary (to the extent required herein), to examine the documents and determine whether to take up or refuse the documents and to inform Beneficiary accordingly.

In the event of an act of God, riot, civil commotion, insurrection, war or any other cause beyond Issuer's control that interrupts Issuer's business and causes the place for presentation of this Letter of Credit to be closed for business on the last day for presentation, the expiry date of this Letter of Credit will be automatically extended without amendment to a date thirty (30) calendar days after the place for presentation reopens for business.

ISSUER:

By: _____
Authorized Signature

EXHIBIT "A"
TO LETTER OF CREDIT

SIGHT DRAFT

Draft Number _____
$_____

At sight, pay to the order of [Name of Beneficiary to be inserted], the amount of USD $_____ (_____ and 00/100ths U.S. Dollars).

Value received and charged to the account of: [Name of Issuer and address]. Drawn under [Name of Issuer to be inserted] Standby Letter of Credit No. _____.

Dated: _____ [Public Service Company of Colorado]

By: _____
[name and title]

Account: [Applicant to be inserted]

EXHIBIT "B"
TO LETTER OF CREDIT

FORM OF TRANSFER REQUEST

Irrevocable Standby Letter of Credit No. _____

Current Beneficiary:	Applicant:
_____	_____
_____	_____
_____	_____
_____	_____

To: [Name of Issuer] ("Issuer")

The undersigned, as the current "Beneficiary" of the above-referenced Letter of Credit, hereby requests that you reissue the Letter of Credit in favor of the transferee named below [insert transferee name and address below]:

_____
_____
_____
_____

From and after the date this transfer request is delivered to Issuer, the transferee shall be the "Beneficiary" under the Letter of Credit for all purposes and shall be entitled to exercise and enjoy all of the rights, privileges and benefits thereof.

Dated: _____

[Public Service Company of Colorado]

By: _____
Name: _____
Title: _____

[Notary Acknowledgement]

To be signed by a person purporting to be an authorized representative of Beneficiary and indicating his or her title or other official capacity, and acknowledged by a notary public.

EXHIBIT E

FORM OF GUARANTY

GUARANTY

This Guaranty is executed and delivered as of this ____ day of _____, 20__ by _____, a _____ [corporation] ("Guarantor"), in favor of [Public Service Company of Colorado] ("Company"), in connection with the performance by _____, a _____ [limited liability company] ("Seller") of a Non-Wires Alternative Services Agreement dated _____, 20____ between Seller and Company (the "NWA Agreement").

- RECITALS –

A. Seller proposes to provide Non-Wires Alternative Services to the Company.

B. Seller and Company have entered into the NWA Agreement on the terms and conditions set forth therein.

C. Seller is controlled by Guarantor. Guarantor expects to derive substantial benefits from the performance of the NWA Agreement by Seller and Company. To induce Company to enter into and continue the NWA Agreement, Guarantor has agreed to guarantee the obligations of Seller as provided in this Guaranty.

NOW, THEREFORE, in consideration of the foregoing, Guarantor agrees as follows:

- AGREEMENT -

1. Guaranty. Subject to the provisions of this Guaranty, Guarantor hereby absolutely, irrevocably, unconditionally, and fully guarantees to Company the due, prompt, and complete observance, performance, and discharge of each and every payment obligation of Seller under the NWA Agreement, whether incurred before or after the date of delivery of this Guaranty (the "Obligations"). This is a guaranty of payment, not of collection, and as such, Company shall not be required to institute, pursue, or exhaust any remedies against Seller before instituting suit, obtaining judgment, and executing thereon against Guarantor under this Guaranty. This Guaranty shall survive termination of the NWA Agreement to the extent necessary to enforce and complete the rights, duties and obligations of Company and Seller thereunder.

2. Maximum Liability. Notwithstanding anything herein to the contrary, Guarantor's maximum liability under this Guaranty shall be limited to _____ dollars (US$_____) plus costs of collection under Section 10 below.

3. Rights of Company. Guarantor hereby grants to Company, in Company's discretion and without the need to notify or obtain any consent from Guarantor, and

without termination, impairment, or any other effect upon Guarantor's duties hereunder, the power and authority from time to time:

(a) to renew, compromise, extend, accelerate, or otherwise change, substitute, supersede, or terminate the terms of performance of any of the Obligations, in each case in accordance with the NWA Agreement;

(b) to grant any indulgences, forbearances, and waivers, on one or more occasions, for any length of time, with respect to Seller's performance of any of the Obligations; and

(c) to accept collateral, further guaranties, and/or other security for the Obligations, and, if so accepted, then to impair, exhaust, exchange, enforce, waive, or release any such security.

4. Performance. If any of the Obligations are not performed according to the tenor thereof, and any applicable notice and cure period provided by the NWA Agreement has expired ("Default"), Guarantor shall immediately upon receipt of written demand by Company (a) perform or cause Seller to perform the Obligation in Default, and (b) pay, reimburse, and indemnify Company against any liabilities, damages, and related costs (including attorneys' fees) incurred by Company as a result thereof, all in such manner and at such times as Company may reasonably direct.

5. Satisfaction. Satisfaction by Guarantor of any duty hereunder incident to a particular Default or the occurrence of any other Default shall not discharge Guarantor except with respect to the Default satisfied, it being the intent of Guarantor that this Guaranty be continuing until such time as all of the Obligations have irrevocably been discharged in full, at which time this Guaranty shall automatically terminate. If at any time the performance of any Obligation by Seller or Guarantor is rescinded or voided under the federal Bankruptcy Code or otherwise, then Guarantor's duties hereunder shall continue and be deemed to have been automatically reinstated, restored, and continued with respect to that Obligation, as though the performance of that Obligation had never occurred, regardless of whether this Guaranty otherwise had terminated or would have been terminated following or as a result of that performance.

6. Notice of Acceptance. Guarantor waives and acknowledges notice of acceptance of this Guaranty by Company.

7. Waivers by Guarantor. Guarantor hereby waives and agrees not to assert or take advantage of:

(a) all set-offs, counterclaims, and, subject to Section 4 above, all presentments, demands for performance, notices of non-performance, protests, and notices of every kind that may be required by Applicable Laws;

(b) any right to require Company to proceed against Seller or any other person, or to require Company first to exhaust any remedies against Seller or any other person, before proceeding against Guarantor hereunder;

(c) any defense based upon an election of remedies by Company;

(d) any duty of Company to protect or not impair any security for the Obligations;

(e) the benefit of any laws limiting the liability of a surety;

(f) any duty of Company to disclose to Guarantor any facts concerning Seller, the NWA Agreement, or any other circumstances, that would or allegedly would increase the risk to Guarantor under this Guaranty, whether now known or hereafter learned by Company, it being understood that Guarantor is capable of and assumes the responsibility for being and remaining informed as to all such facts and circumstances; and

(g) until all Obligations in Default have been fully paid and/or performed, any rights of subrogation, contribution, reimbursement, indemnification, or other rights of payment or recovery for any payment or performance by it hereunder. For the avoidance of doubt, if any amount is paid to Guarantor in violation of this provision, such amount shall be held by Guarantor for the benefit of, and promptly paid to, Company.

8. Cumulative Remedies. The rights and remedies of Company hereunder shall be cumulative and not alternative to any other rights, powers, and remedies that Company may have at law, in equity, or under the NWA Agreement. The obligations of Guarantor hereunder are independent of those of Seller and shall survive unaffected by the bankruptcy of Seller. Company need not join Seller in any action against Guarantor to preserve its rights set forth herein.

9. Representations and Warranties. Guarantor represents and warrants to Company as follows:

(a) Guarantor is a corporation, duly organized, validly existing, and in good standing under the laws of the state of its incorporation. Seller is a direct or indirect wholly-owned subsidiary of Guarantor. Guarantor has all necessary corporate power and authority to execute and deliver this Guaranty and to perform its obligations hereunder.

(b) The execution, delivery and performance of this Guaranty has been duly and validly authorized by all corporate proceedings of Guarantor and is not in violation of any law, judgment of court or government agency. This Guaranty has been duly and validly executed and delivered by Guarantor and constitutes a legal, valid and binding obligation of Guarantor, enforceable against Guarantor in accordance with its terms.

10. Collection Costs. Guarantor shall pay to Company, upon demand, and in addition to the maximum liability set forth in Section 2 hereof, all reasonable attorneys' fees and other expenses which Company may expend or incur in enforcing the Obligations against Seller and/or enforcing this Guaranty against Guarantor, whether or not suit is filed, including, without limitation, all attorneys' fees, and other expenses incurred by Company in connection with any insolvency, bankruptcy, reorganization,

arrangement, or other similar proceedings involving Seller that in any way affect the exercise by Company of its rights and remedies hereunder.

11. Severability. Should any one or more provisions of this Guaranty be determined to be illegal or unenforceable, all other provisions nevertheless shall be effective.

12. Waiver or Amendment. No provision of this Guaranty or right of Company hereunder can be waived, nor can Guarantor be released from Guarantor's duties hereunder, except by a writing duly executed by Company. This Guaranty may not be modified, amended, revised, revoked, terminated, changed, or varied in any way whatsoever except by the express terms of a writing duly executed by Company.

13. Successors and Assigns. This Guaranty shall inure to the benefit of and bind the successors and assigns of Company and Guarantor.

14. Governing Law. This Guaranty shall be governed by and construed in accordance with the law of the State of [*insert home state of Company*] without regard to the principles of conflicts of law thereof. Venue for any dispute hereunder shall be as set forth in the NWA Agreement.

15. Notices. All notices, requests, claims, demands, and other communications hereunder shall be in writing and shall be given (and shall be deemed to have been duly given upon receipt) by delivery in the manner contemplated by the NWA Agreement, addressed as follows:

(a) *if to Company*: as provided in the NWA Agreement

(b) *if to Guarantor*: _____
_____
_____
Attn:

with a copy to: _____
_____
_____
Attn:

or to such other address (es) as the person to whom notice is given may have previously furnished to the others in writing in the manner set forth above.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered to Company as of the day and year first above written.

[Name of Guarantor]

By:_____
Name:
Title:

STATE OF_____)
) ss.
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 20___, by _____, as _____ of _____.

Witness my hand and official seal.

My commission expires: _____.

(S E A L)

_____
Notary Public

EXHIBIT F

NOTICES AND CONTACT INFORMATION

NON-WIRES ALTERNATIVE SERVICES AGREEMENT

BETWEEN

PUBLIC SERVICE COMPANY OF COLORADO
("COMPANY")

AND

[_____]
("SERVICE PROVIDER")



- [date] -

Table of Contents:

Contents

Article 1 - Rules of Interpretation ..... 1~~13~~
Article 2 - Definitions ..... 3~~34~~
Article 3 - Term and Termination ..... 7~~68~~
Article 4 - Service Provider's Obligations ..... 9~~810~~
Article 5 - Payment ..... 12~~1214~~
Article 6 - Security for Performance ..... 13~~1214~~
Article 7 - Default and Damages ..... 15~~1517~~
Article 8 - Dispute Resolution ..... 20~~2021~~
Article 9 - Representations and Warranties ..... 21~~2022~~
Article 10 - Indemnification and Insurance ..... 22~~2123~~
Article 11 - Miscellaneous ..... 24~~2425~~

Exhibits:

EXHIBIT A NWA SERVICES
EXHIBIT B NWA SERVICES GUARANTEE
EXHIBIT C NWA SERVICES PAYMENT RATE
EXHIBIT D FORM OF LETTER OF CREDIT
EXHIBIT E FORM OF GUARANTY
EXHIBIT F NOTICES AND CONTACT INFORMATION

NON-WIRES ALTERNATIVE SERVICES AGREEMENT
BETWEEN
PUBLIC SERVICE COMPANY OF COLORADO
AND
[_____]

This Non-Wires Alternative Services Agreement (this "Agreement") is made this [_____] day of [_____, 20__], by and between (i) **Public Service Company of Colorado**, a Colorado corporation with a principal place of business at 1800 Larimer Street, Suite 1000, Denver, Colorado 80202 ("Company"), and (ii) [_____], ~~a~~n [state] [legal entity] ~~[LLC]~~ with a principal place of business at [_____] ("Service Provider"). Company and Service Provider are hereinafter referred to individually as a "Party" and collectively as the "Parties."~~.~~

Formatted: Underline

Formatted: Underline

Formatted: Underline

WHEREAS, the Colorado Public Utilities Commission ("CPUC") has required the Company, in certain circumstances, to conduct a technology-neutral competitive solicitation for Non-Wires Alternatives ("NWA") to defer, reduce, or avoid the costs of Major Distribution Grid Projects;

WHEREAS, the Company issued a technology-neutral request for proposals for Non-Wires Alternatives ("RFP");

WHEREAS, Service Provider desires to sell and deliver such Non-Wires Alternative Services ("NWA Services") as more fully described in Exhibit A – NWA Services attached to this Agreement, and Company desires to accept and receive such NWA Services on the terms and conditions set forth in this Agreement.

NOW THEREFORE, in consideration of the mutual covenants herein contained, the sufficiency and adequacy of which are hereby acknowledged, the Parties agree to the following:

Article 1 - Rules of Interpretation

1.1 Interpretation.

(A) Capitalized terms listed in this Agreement shall have the meanings set forth in Article 2 - Definitions or as otherwise defined in this Agreement, whether in the singular or the plural or in the present or past tense. Words not otherwise defined in this Agreement shall (i) have meanings as commonly used in the English language, (ii) be given their generally accepted meaning consistent with Good Utility Practice, and (iii) be given their well-known and generally accepted technical or trade meanings.

(B) The following rules of interpretation shall apply: (~~1~~i) references to "Articles," "Sections," or "Exhibits" shall be to articles, sections, or exhibits of this Agreement except as the context may otherwise require; (~~2~~ii) all Exhibits are incorporated into this Agreement (*provided*, *however*, that in the event of a conflict with the terms of this Agreement, the Agreement shall control); and (~~3~~iii) use of the words "include" or

"including" or similar words shall be interpreted as "include without limitation" or "including, without limitation."

(C) None of the provisions of this Agreement shall be construed against one Party on the ground that such Party is the author of this Agreement or any part hereof.

1.2 Interpretation with Other Agreements. This Agreement does not modify the Parties' rights and obligations under any applicable Company r~~R~~ate ~~S~~schedule (if Service Provider is a customer of Company) or existing service agreement between the Parties. This Agreement does not provide Service Provider with authorization to interconnect or inject power into the Distribution Authority's System. Service Provider shall contract for any interconnection services in accordance with the applicable Distribution Tariff. Service Provider acknowledges that the Interconnection Agreement is/will be a separate contract and that (i) this Agreement is not binding on the Distribution Authority, (ii) this Agreement does not create any rights between Service Provider and the Distribution Authority nor any obligations on Distribution Authority to Service Provider with respect to this Agreement, and (iii) the Interconnection Agreement does not modify the Parties' rights and obligations under this Agreement. The applicable Distribution Authority shall be deemed to be a separate and unaffiliated contracting party for purposes of this Agreement, regardless whether such Distribution Authority is Company or an Affiliate of Company. To that end, any breach, dispute, or other issue related to the Distribution Authority's performance under any Interconnection Agreement or other conduct by the Distribution Authority related to the ~~Interconnection~~ interconnection ~~Procedures~~ procedures and ~~Standards~~ standards ~~or an Interconnection Agreement~~with respect to interconnection shall not be considered a breach by the Company of its obligation of good faith and fair dealing or any other statutory or common law requirement with respect to this Agreement and Service Provider waives any and all claims at equity or law related thereto. Likewise, any breach, dispute, or other issue related to the Company's performance of this Agreement or other conduct by Company related to this Agreement shall not be considered a breach by the Distribution Authority of its obligation of good faith and fair dealing or any other statutory or common law requirement under an Interconnection Agreement or the associated i~~I~~nterconnection p~~P~~rocedures and s~~S~~tandards and Service Provider agrees to waive any and all claims at equity or law related thereto.

1.3 Good Faith and Fair Dealing. The Parties shall act reasonably and in accordance with the principles of good faith and fair dealing in the performance of this Agreement. Unless expressly provided otherwise in this Agreement, (a) when this Agreement specifically references the consent, approval, or similar action by a Party, such consent or approval shall not be unreasonably withheld, conditioned or delayed, and (b) wherever this Agreement specifically gives a Party a right to determine, require, specify or take similar action with respect to a matter, such determination, requirement, specification or similar action shall be Commercially Reasonable.

Article 2 - Definitions

The following terms shall have the meanings set forth herein:

2.1 "Actual Damages" shall have the meaning provided in Section 7.3(B).

2.2 "Agreement" shall have the meaning set forth in the introductory paragraph.

~~2.1~~2.3 "Applicable Law" means all laws, statutes, treaties, codes, ordinances, regulations, certificates, orders, licenses and permits of any Governmental Authority that are applicable to a Party, the business of a Party or the NWA Services, now in effect or hereafter enacted, including amendments to or interpretations of any of the foregoing by a Governmental Authority having jurisdiction, and all applicable judicial, administrative, arbitration and regulatory decrees, judgments, injunctions, writs, orders, awards or like actions.

~~2.2~~2.4 "Business Day" means any Day that is not a Saturday, a Sunday, or a ~~NERC~~ recognized holiday in the State of Colorado.

~~2.3 "Capacity Need" shall have the meaning set forth in CPUC Rules, Sec. 3527.~~

~~2.4~~2.5 "Commercial Operation" shall mean that all equipment required for provision by Service Provider of the NWA Services shall have been installed, tested, and commissioned, that equipment and facilities, if any, necessary to connect with the Company's distribution grid have been installed, tested, and commissioned, that requirements of any applicable Interconnection Agreement(s) necessary for provision of NWA Services have been satisfied, and that the NWA Services are operational and capable of achieving the NWA Services Guarantee.

~~2.5~~2.6 "Commercial Operation Year" shall have the meaning set forth in Section 4.1(G).

~~2.6~~2.7 "Commercially Reasonable" or "Commercially Reasonable Efforts" means, with respect to any action to be taken or attempted by a Party under this Agreement, the level of effort in light of the facts known to such Party at the time a decision is made that: (a) can reasonably be expected to accomplish the desired action at a reasonable cost; (b) is consistent with Good Utility Practices; and (c) takes into consideration the amount of advance notice required to take such action, the duration and type of action and the competitive environment in which such action occurs.

2.8 "Company" shall have the meaning set forth in the introductory paragraph.

~~2.7~~2.9 "CPUC" shall mean the Colorado Public Utilities Commission or any successor agency.

~~2.8~~2.10 "CPUC Rules" shall mean the Colorado Public Utilities Commission's Rules Regulating Electric Utilities, codified at 4 Code of Colorado Regulations 723-3, as

Formatted: Underline

Formatted: Underline

promulgated by the CPUC and amended from time to time. References in this Agreement to CPUC Rules shall include successor rules.

~~2.9~~2.11 "Credit Rating" of any Person means the lowest rating assigned to such Person's long-term debt or deposit obligations (unenhanced by third-party support) by Standard & Poors and Moody's. If such Person has no outstanding long-term debt or deposit obligations, or if no rating is assigned to such obligations, "Credit Rating" shall mean the lowest general corporate credit rating or long-term issuer rating assigned to such Person by Standard & Poors or Moody's.

~~2.10~~2.12 "Day" means a calendar day.

~~2.11~~2.13 "Demand Reduction" shall mean a reduction in load, congestion, or other constraints at specified locations on the grid.

~~2.12 "Demand Response Measures" or "Demand Response" or "DR" shall have the meaning set forth in CPUC Rules, Sec. 3527.~~

~~2.13 "Dispute" shall have the meaning set forth in Article XX.~~

~~2.14 "Distributed Energy Resources" or "DER" shall have the meaning set forth in CPUC Rules, Sec. 3527.~~

~~2.15~~2.14 "Distribution Authority" means collectively those entities owning and/or operating the interconnected ~~transmission~~ distribution system applicable to Service Provider pursuant to a Distribution Tariff, including (i) ~~PSCo~~ Company operating under and in accordance with its Distribution Tariff, and (ii) all entity(ies) responsible under the Interconnection Agreement for providing the ~~transmission~~ distribution lines, any i~~I~~nterconnection f~~F~~acilities and other equipment and facilities that interconnects at the Interconnection Point and distribution system.

~~2.16~~2.15 "Distribution Authority's System" means the contiguously interconnected electric ~~transmission and sub-transmission~~ distribution facilities owned or operated by the Distribution Authority~~, over which the Distribution Authority has rights (by ownership or contract) to provide transmission of energy from the Interconnection Point~~.

~~2.17 "Distribution System Plan" or "DSP" shall have the meaning set forth in CPUC Rules, Sec. 3527.~~

~~2.18~~2.16 "Distribution Tariff" means the applicable tariff of the Distribution Authority, as amended from time to time.

~~2.19~~2.17 "Effective Date" shall have the meaning set forth in Section 3.1.

~~2.20 "Energy Efficiency Measures" shall have the meaning set forth in CPUC Rules, Sec. 3527.~~

~~2.21~~2.18 "Event of Default" shall have the meaning set forth in Article 7.

Formatted: Indent: Left: 0.5", No bullets or numbering

Formatted: Underline

~~2.22~~2.19 "Good Utility Practices" means the practices, methods, standards and acts engaged in or approved by a significant portion of the applicable segment of the electric utility industry pertaining to services of the similar type and size to the NWA Services that, at a particular time, in the exercise of Commercially Reasonable judgment, in light of the facts that are known (or reasonably should have been known) at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with Applicable Law, permits, codes, standards, equipment manufacturer's recommendations, reliability, safety, environmental protection, economy, and expedition. Good Utility Practices is not limited to the optimum practice, method, standard or act to the exclusion of all others, but rather to those practices, methods, standards and acts generally acceptable or approved by a significant portion of the applicable segment of the electric power generation industry in the relevant region, during the relevant period.

~~2.23~~2.20 "Governmental Authority" means any federal, state, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power; or any court or governmental tribunal.

~~2.24 "Grid Need" shall have the meaning set forth in CPUC Rules, Sec. 3527.~~

~~2.25~~2.21 "Guarantor" shall have the meaning set forth in Section ~~67.23~~(C).

~~2.26~~2.22 "Interconnection Agreement" means the separate contract for interconnection to the Distribution Authority's System, as such agreement may be amended from time to time. For purposes of this Agreement, the Interconnection Agreement shall be interpreted to include any third party facility construction agreement or other agreement required by the Distribution Authority in accordance with the Distribution Tariff.

~~2.27~~2.23 "Interconnection Point" means the physical point within the operational authority of the Distribution Authority at which electrical interconnection is made with the Distribution Authority's System in accordance with the Distribution Tariff and the Interconnection Agreement.

~~2.28~~2.24 "Investment Grade" means a Credit Rating of both (a) Baa3 or higher by Moody's, and (b) BBB- or higher by Standard & Poors.

~~2.29~~2.25 "kW" means kilowatt and "kWh" means kilowatt hour.

~~2.30~~2.26 "Maintenance Schedule" is defined in Section 4.4(A).

~~2.31~~2.27 "Major Distribution Grid Project" shall have the meaning set forth in CPUC Rules, Sec. 3527.

~~2.32~~2.28 "Material Adverse Effect" means any effect (or effects taken together) that is materially adverse to the present or future business, operations, assets, liabilities,

Formatted: Indent: Left: 0.5", No bullets or numbering

Formatted: Underline

properties, results in operations or condition (financial or otherwise), prospects, or property of a Party, its business, or this Agreement.

~~2.33~~2.29 "Metering Point" means the physical point at which Service Provider makes available and delivers to Company the NWA Services being provided by Service Provider to Company under this Agreement. The Metering Point is specified in Exhibit A ~~– Description of~~ NWA Services.

~~2.34 "MVA" means megavolt amperes.~~

~~2.35~~2.30 "MW" means megawatt or one thousand kW and "MWh" means megawatt hours.

~~2.36~~2.31 "Non-Wires Alternative" or "NWA" shall have the meaning set forth in CPUC Rules, Sec. 3527.

~~2.37~~2.32 "NWA Services" shall refer to those services specified in Exhibit A.

~~2.38~~2.33 "NWA Services Guarantee" shall have the meaning set forth in Section ~~54~~.2.

~~2.39~~2.34 "NWA Services Guarantee Breach" shall have the meaning set forth in Section ~~75~~.2(A).

~~2.40 "Operating Records" means all agreements associated with the NWA Services, operating logs, blueprints for construction, operating manuals, all warranties on equipment, and all documents, whether in printed or electronic format, that Service Provider uses or maintains for the operation of the NWA Services~~.

2.35 "Party" and "Parties" shall have the meanings set forth in the introductory paragraph.

~~2.41~~2.36 "Peak Demand Event" shall have the meaning set forth in Exhibit B.

2.37 "PUC Approval" has the meaning set forth in Section 3.2(A)5.

~~2.42~~2.38 "Required In-Service Date" is as defined in Section 4.1(C).

~~2.43~~2.39 "Security Fund" shall have the meaning set forth in Section ~~76~~.1(A).

2.40 "Service Provider" shall have the meaning set forth in the introductory paragraph.

~~2.44~~2.41 "Term" means the period of time during which this Agreement shall remain in full force and effect as further ~~defined~~ provided in Article 3.

~~2.45 "Year" means a calendar year.~~

Formatted: Underline
Formatted: Underline
Formatted: Underline
Formatted: Underline
Formatted: Indent: Left: 0.5", No bullets or numbering
Formatted: Underline
Formatted: Underline
Formatted: Underline
Formatted: Underline
Formatted: Underline
Formatted: Indent: Left: 0.5", No bullets or numbering

Article 3 - Term and Termination

3.1 Term. This Agreement shall become effective as of the date of its execution ("Effective Date"), and shall remain in full force and effect until 11:59 pm on the last Day of the ~~fifth~~ [insert] (X~~5~~th) Commercial Operation Year (the "Scheduled Termination Date"), subject to early termination as provided for in this Agreement.

3.2 Conditions Precedent.

(A) PUC Approval.

1. No later than forty-five (45) Days after the Effective Date, Company may apply to the CPUC for PUC Approval. If Company fails to apply for PUC Approval within forty-five (45) Days following the Effective Date, Company shall be deemed to have waived its right to obtain PUC Approval and to terminate this Agreement under this Section 3.2, and this Agreement shall remain in full force and effect thereafter.

2. If Company applies for PUC Approval, Company shall use Commercially Reasonable Efforts to obtain PUC Approval as soon as reasonably practicable. Seller shall cooperate with Company's efforts to obtain PUC Approval.

3. If Company applies for PUC Approval, Company shall have the right to terminate this ~~PPA~~Agreement, without any further financial or other obligation to Seller as a result of such termination, by notice to Seller

a. at any time within thirty (30) Days following issuance of a written order by the PUC rejecting PUC Approval, or granting PUC Approval with conditions unacceptable to Company in its sole discretion;

b. at any time between the two hundred fiftieth (250th) and two hundred eightieth (280th) Day] following Company's application for PUC Approval, if prior to the date of such termination the PUC has not issued a written order granting or rejecting PUC Approval;

c. at any time within thirty (30) Days following timely request for reconsideration (in whole or in any material part) by any third party with standing, of a written PUC order granting PUC Approval; and/or

d. at any time within thirty (30) Days following timely appeal by any party with standing, of a written PUC order granting PUC Approval.

4. If Company is eligible but fails to terminate this ~~PPA~~ Agreement by the applicable date, Company shall be deemed to have waived its right to terminate this ~~PPA~~ Agreement for that reason, and this ~~PPA~~ Agreement shall remain in full force and effect thereafter.

Formatted: Heading 4

~~4.~~5. For purposes of this ~~PPA~~Agreement, "PUC Approval" means a written order of the CPUC making an affirmative determination that all costs incurred

under this Agreement are recoverable from Company's retail customers pursuant to Applicable Law, subject only to the requirement that the PUC retains ongoing prudency review of Company's performance and administration of this Agreement, as determined by Company in its sole discretion.

(B) Other Company CPs. [*if any*].

(C) Service Provider CPs. [if any - bid specific].

(D) Return of Security Fund.

Following a termination pursuant to Section 3.2(A) [or Section 3.2(~~C~~B)] [or Section 3.2(~~D~~C)], the Company will return to Seller the initial Security Fund within five (5) Business Days of such termination.

(E) The Service Provider must achieve Commercial Operations on or before the Required In-Service Date set forth in Section 4.1(C). Achievement of Commercial Operation by such date and PUC Approval pursuant to this Section 3.2 are conditions precedent for the Company's obligations set forth in this Agreement.

Formatted: Underline

Formatted: Underline

(F) Receipt by the Service Provider from applicable Governmental Authorities of all necessary permits, licenses, approvals, and authorizations necessary for approval of this Agreement and provision by Service Provider of the NWA Services is a condition precedent for the Company's obligations set forth in this Agreement.

3.3 Early Termination.

(A) Company may immediately terminate this Agreement upon written notice to Service Provider if Service Provider breaches any material obligation under this Agreement and fails to cure such breach within fifteen (15) ~~calendar d~~Days after receiving written notice of the breach. Service Provider must notify Company in writing upon curing the identified breach.

(B) Service Provider may request to terminate this Agreement by submitting written notice to the Company. The termination will be effective on the later of (i) the beginning of the calendar month that is immediately after the initial 12 month term, and (ii) the beginning of the calendar month that is closest to but at least thirty (30) ~~calendar d~~Days after the Company received the notice. Upon delivery of a termination notice pursuant to this Section, Service Provider shall pay to Company by check or wire transfer of immediately available funds, a termination payment in an amount equal to the total amount payable by Company to Service Provider during the remaining term of this Agreement~~ ("Remaining Contract Value"),~~

3.4 Effect of Termination. Applicable provisions of this Agreement shall continue in effect after termination to the extent necessary to (i) provide for final billings, payments and adjustments, (ii) enforce or complete the duties, obligations or responsibilities of the Parties under this Agreement ~~(including under [Section XX,~~

~~Section XX, and Article XX] below)~~, and (iii) address any remedies or indemnifications arising prior to termination.

Article 4 - Service Provider's Obligations

4.1 NWA Services. Service Provider shall deliver the NWA Services as described in Exhibit A – ~~Description of~~ NWA Services during the Term of this Agreement.

(A) Service Provider shall procure all equipment and services necessary to fulfill its obligations under this Agreement. Service Provider must also provide to Company the ability to appropriately inform Service Provider when the NWA Services are required to be delivered.

(B) If necessary to provide the NWA Services, Service Provider shall be responsible for arranging, maintaining and paying the costs associated with the interconnection to the Distribution Authority's System, and shall comply with the Distribution Authority's requirements for interconnection and all requirements set forth in the applicable Distribution Tariff.

(C) Service Provider must cause the NWA Services to achieve Commercial Operation by [–_____] ("the "Required In-Service Date")

Formatted: Underline

(D) Service Provider shall notify Company of the date on which Service Provider believes Commercial Operation has been achieved (a "COD Notice"). A COD Notice shall include all necessary supporting documentation of the satisfaction or occurrence of all COD Conditions. Company shall have ten (10) Business Days to review a COD Notice and raise any Commercially Reasonable objection to Service Provider's satisfaction of any of the COD Conditions, *provided*, *however*, that Service Provider's COD Notice shall be deemed accepted by Company if Company fails to object within such time period. Service Provider may notify Company of completion of one or more COD Conditions on an individual and incremental basis prior to COD, *provided*, *however*, that Company shall in all cases have up to ten (10) Business Days to review and object to each such notice.

(E) For purposes hereof, the "Commercial Operation Date" or "COD" means 12:01 am on the Day after which Service Provider's COD Notice has been accepted by Company or deemed accepted by Company pursuant to this Section.

(F) the "COD Conditions" are

1. an officer of Service Provider, authorized to bind Service Provider and who is familiar with the NWA Services, has confirmed in writing that:

a. all necessary and material ~~Permits~~ permits have been obtained, are in full force and effect and the entity granting the ~~Permit~~ permit has not placed any temporary or conditional restrictions or limitations on the ~~Facility or its operation~~Service Provider's ability to provide the NWA Services in conformance with the terms of this Agreement,

b. Seller is in compliance with this Agreement in all material respects,

c. the NWA Services are available to be provided in accordance with Service Provider's operating agreements, contracts, and manufacturers' warranties,

d. Service Provider has proven to Company's reasonable satisfaction that

i. Service Provider and the Distribution Authority have executed the Interconnection Agreement, if any, and Service Provider has received no notice of breach thereof from the Distribution Authority,

ii. Service Provider has or is capable of declaring commercial operation under the Interconnection Agreement, if any, and

iii. Seller has made all other arrangements necessary to deliver the NWA Services during the Term;

e. Seller has executed and delivered to Company all Security Fund documents or instruments required under Article ~~XXX~~6.

Formatted: Underline

(G) For purposes hereof, the first "Commercial Operation Year" shall mean the period starting at 12:01 a.m. on January 1st following the Commercial Operation Date and ending at 11:59 pm on the last Day of such calendar year, and each successive "Commercial Operation Year" shall mean the 12-month period following the prior Commercial Operation Year.

1. If necessary to provide the NWA Services, Service Provider shall be responsible for arranging, maintaining and paying the costs associated with the interconnection to the Distribution Authority's System, if any~~,~~, and shall comply with the Distribution Authority's requirements for interconnection and all requirements set forth in the applicable Distribution Tariff, to the extent required for the provision of the NWA Services.

4.2 NWA Services Guarantee.

(A) Service Provider guarantees that the NWA Services provided for in Exhibit A –NWA Services will, when installed: (1) achieve at least ninety percent (90%) of the kW of Demand Reduction provided for in Exhibit A –NWA Services during a p~~P~~eak d~~D~~emand e~~E~~vent for the specified duration; (2) provide such Demand Reduction at the portion(s) of the distribution grid specified in Exhibit A –NWA Services; and (3) be operationally available by the Required In-Service Date (the foregoing clauses (1) through (3) being collectively referred to herein as the "NWA Services Guarantee"). The NWA Services Guarantee also encompasses the guarantees set forth in Exhibit B.

Formatted: Underline

(B) Service Provider guarantees that it can and will achieve the ~~Delivery of~~ NWA Services Guarantee when the Company declares a pPeak dDemand eEvent applicable to the Service Provider's NWA Services.

(C) Service Provider's receipt of Payments under this Agreement is conditioned upon the truth and accuracy of its NWA Services Guarantee and the performance of its obligations hereunder.

4.3 Measurement and Verification.

(A) The kW Demand Reduction delivered by Service Provider will be measured at the Metering Point by the Company or a third-party contractor selected and retained by the Company. Service Provider shall fund the cost of any additional advanced metering equipment that the Company determines, in its sole discretion, is necessary to measure and verify the NWA Services provided.

(B) In lieu of Section ~~5~~4.3(A)~~,~~ above, and if deemed appropriate by mutual agreement of the Parties, the measurement and verification protocols to measure Demand Reduction for the NWA Services that may be established in a measurement and verification plan ("M&V Plan"). The M&V Plan will include, among other things, witness testing and appropriate verification.

Formatted: Underline

(C) Payment to Service Provider for the NWA Services pursuant to Article ~~6~~ 5 is dependent upon measurement and verification. Performance data of the NWA Services will be reviewed and verified as established in the M&V Plan or measurement pursuant to (A) above before Payment is remitted to Service Provider. Company shall have full rights to audit the books and records of Service Provider to determine compliance with this Agreement and the ~~Delivery of~~ NWA Services Guarantee.

~~(C)~~(D) Service Provider shall provide annual reports to the Company regarding whether and to what extent the NWA Services produce benefits to disproportionally impacted communities. The annual reports shall compare realized benefits to any predicted benefits presented to the Company prior to entry into this Agreement and shall discuss the reasons for any shortfall in actual benefits as compared to previously predicted benefits.

4.4 Operations and Maintenance. Service Provider shall maintain any facilities necessary to deliver the NWA Services in accordance with Good Utility Practices. Such maintenance shall include replacement or repair, whichever is appropriate under Good Utility Practices, of degraded or damaged equipment, and other such other maintenance as is necessary to continue to reliably deliver the NWA Services.

(A) Service Provider shall provide the Company with a schedule of the expected Scheduled Outages for the NWA Services for the first year following the Effective Date ("Maintenance Schedule"), including the start time and expected duration of the outage. Service Provider shall update the Maintenance Schedule annually. Absent the prior written consent of the Company, Service Provider shall schedule all its outages during the months of October and November.

(B) Service Provider shall maintain an accurate and up-to-date record of every time the NWA Services are dispatched by the Company, and shall deliver such information to the Company within five (5) Business Days after the end of any month in which the NWA Services are dispatched.

(C) Representatives of Company shall have access to any facilities necessary to deliver the NWA Services from time to time, on Commercially Reasonable prior notice, to read and/or test meters, perform inspections and take such other actions as may be appropriate to facilitate Company's performance under this Agreement.

(D) Service Provider may indicate that certain information and data to which the Company is given access is confidential and certain other information may be confidential pursuant to applicable data privacy laws ("Confidential Information"). Regardless of the confidentiality, all such Confidential Information may be subject to: 1) state and federal freedom of information and open records act laws; 2) review by the appropriate state jurisdiction; 3) any other governmental authority or judicial body with jurisdiction relating to these matters; and 4) legal and regulatory discovery. Under such circumstances, the Company shall notify the Service Provider regarding such circumstances to allow it to seek a protective order, as appropriate, or otherwise prevent the disclosure of the Confidential Information, as legally permitted. The Company shall make all reasonable efforts to preserve the confidentiality of the Confidential Information, but Service Provider and the Company acknowledge that such treatment is neither automatic nor guaranteed. The Company and Respondent also specifically anticipate that Confidential Information may be filed with the CPUC and agree to such disclosure provided the filing party seeks an appropriate protective order.

Formatted: Underline

4.5 Removal of Equipment. Service Provider agrees that any and all project-related removal and disposal of equipment or materials, including disposal because equipment, facilities, or materials have reached the end of useful life and/or as a result of a termination of this Agreement, will be conducted at its sole cost and expense and in accordance with all applicable laws, rules, and regulations.

Article 5 - Payment

5.1 Payment to Service Provider. The Company will pay Service Provider for the NWA Services ~~services~~ rendered under this Agreement as follows.

(A) In exchange for being available to provide the ~~Delivery of~~ NWA Services Guarantee during Peak Demand Events, the Company will make Payments to Service Provider as set forth in Exhibit A –NWA Services.

(B) Subject to the other applicable provisions of this Agreement, Company will make each annual NWA Services Payment in a single lump sum on the last day of each Commercial Operation Year during the Term of this Agreement, *provided*, that the Company will only make Payments if (1) the Service Provider performed during Peak Demand Events during the applicable Commercial Operation Year, and (2) the

Demand Reduction provided by Service Provider was verified as provided in this Agreement.

Article 6 - Security for Performance[4]

6.1 Security Fund.

(A) During the Term of this Agreement, Service Provider shall fund and maintain security in favor of Company, at Service Provider's expense, to secure Service Provider's obligations to Company under this Agreement (the "Security Fund"), in accordance with this Article 6.

(B) Service Provider shall establish and fund the initial Security Fund in the amount of no less than the Total Contract Value defined as the sum of all yearly payments set forth in Exhibit C –NWA Services Payment Rate, for the ~~Contract~~ Term, no later than thirty (30) Days following the Effective Date.

Formatted: Font: Not Italic

Formatted: Font: Not Italic, No underline

(C) Company may draw from the Security Fund such amounts as are necessary to recover amounts owing to Company pursuant to this Agreement, including but not limited to any Penalties, Actual Damages, or any amounts for which Company is entitled to indemnification under this Agreement. Company may, in its sole discretion, draw all or any part of such amounts from any form of security to the extent available pursuant to this Article 6 and in any sequence Company may select. Company's failure or delay to draw any amount from the Security Fund in any instance shall not prejudice Company's rights to subsequently recover such amount from the Security Fund or in any other manner.

(D) Company shall notify Service Provider within five (5) Business Days following any draw on the Security Fund by Company, including the amount thereof and the basis therefor.

6.2 Form.

(A) The Security Fund may be in the form of an irrevocable standby letter of credit substantially in the form of Exhibit D - Form of Letter of Credit (a "Letter of Credit") from a financial institution acceptable to Company ("Issuer").

1. The Issuer of the Letter of Credit shall have and maintain a Credit Rating equivalent to A- (or better) by Standard & Poors and A3 (or better) from Moodys. If such Credit Rating is A- or A3, the Issuer must not be on credit watch by any rating agency.

2. The Letter of Credit must be for a minimum term of three hundred sixty (360) Days. Service Provider shall give Company at least thirty (30) Days advance notice prior to any expiration or earlier termination of the Letter of Credit. Service Provider shall cause the renewal or extension of the Letter of Credit for additional

[4] ~~NTD: This is drawn from the form Xcel PPA.~~

consecutive terms of three hundred sixty (360) Days or more (or, if shorter, the remainder of the Term) more than 30 Days prior to each expiration date of the security. If the Letter of Credit is not renewed or extended at least thirty (30) Days prior to its expiration date or otherwise is terminated early, Company shall have the right to draw immediately upon the Letter of Credit and to place the amounts so drawn, at Service Provider's cost and with Service Provider's funds, in an Escrow Account in accordance with paragraph (B) below, until and unless Service Provider provides a substitute form of security meeting the requirements of this Section ~~XX~~6.2.

(B) The Security Fund may be in the form of U.S. currency deposited into an escrow account with a state- or federally-chartered commercial bank with an office in the State of Colorado, with net assets of at least $1 billion (the "Escrow Account").

1. The Escrow Account shall be governed by an escrow and account control agreement in form mutually satisfactory to Service Provider, Company and the escrow agent, provided that (a) Company shall hold a first and exclusive perfected security interest in the funds in the Escrow Account, (b) Company shall be permitted unilaterally to draw down any amount therein, regardless of any protest by Service Provider or any other party liable thereon (*provided* that nothing in the Escrow Agreement shall preclude any protest against Company by Service Provider, following any draw, that such draw did not comply with this Agreement), and (c) Service Provider shall pay all fees and expenses of the escrow agent.

2. Funds held in the Escrow Account may be invested as Service Provider may direct in any of the following:

- a money-market fund sponsored by the escrow agent;
- U.S. treasury obligations with a maturity of ninety (90) Days or less;
- commercial paper rated "A" or better, with a maturity of ninety (90) D~~d~~ays or less; ~~and~~or
- other liquid investment-grade investments with maturities of three months or less, approved by Company in advance (such approval not to be unreasonably withheld or delayed).

3. All investment income on the Escrow Account shall be taxable to, and accrue for the benefit of, Service Provider. After the Commercial Operation Date, periodic sweeps by Service Provider for recovery of interest earned by the escrowed funds shall be allowed, and if at any time the balance in the Escrow Account exceeds the required amount of security, the escrow agent may remit the excess to Service Provider.

(C) The Security Fund may consist of a guaranty substantially in the form of Exhibit E – Form of Guaranty, from a parent or other guarantor ("Guarantor") with a minimum of net worth of at least $250,000,000 and an Investment Grade Credit Rating

(and if such Credit Rating is exactly equivalent to BBB- [~~S&P~~Standard & Poors] / Baa3 [Moody's], the Guarantor must not be on credit watch by any rating agency). If the Credit Rating of the Guarantor is downgraded below Investment Grade, put on credit watch, or an event occurs that (in the reasonable determination of Company) portends a Material Adverse Effect in the creditworthiness of the Guarantor, then Company may require Service Provider to convert the guaranty to a Security Fund instrument meeting the criteria set forth in either paragraph (A) or paragraph (B) above no later than ten (10) Days after notice from Company.

(D) Company shall negotiate in good faith any needed escrow and account control agreement and, upon request by Service Provider, immaterial changes to Exhibit D – Form of Letter of Credit and/or Exhibit E – Form of Guaranty, provided that Service Provider shall pay or reimburse Company for the direct expenses (including the fees and expenses of counsel) incurred by Company in connection therewith.

(E) Service Provider may change the form of the Security Fund at any time and from time to time upon Commercially Reasonable prior notice to Company, provided, however, that the Security Fund must at all times satisfy the requirements of this Article ~~XX~~6.

6.3 Replacement. In the event that the Security Fund ever fails to comply with the requirements of this Article 6 or Company determines in a C~~c~~ommercially R~~r~~easonable manner that an event has occurred or circumstances have developed that threaten to cause the Security Fund to fail to comply with the requirements of this Article ~~XX~~ 6 (e.g., a Guarantor is placed on negative credit watch by a rating agency), Service Provider shall be required to replace the Security Fund with security in compliance with this Article ~~XX~~ 6 within five (5) Days following notice thereof from Company.

Formatted: Underline

6.4 Survival. The Security Fund shall survive termination of this Agreement to be available to pay any amounts owed to Company arising prior to or upon termination. Company may draw such amounts and shall release the balance of the Security Fund (including any accumulated interest, if applicable) to Service Provider.

6.5 Expenses. Service Provider shall reimburse Company for its direct expenses (including the fees and expenses of counsel) incurred by Company in connection with the preparation, negotiation, execution and/or release (including making a draw of funds) of the Security Fund under this Article 6.

Article 7 - Default and Damages

7.1 Default by Service Provider: General.

(A) *Events*. Any of the following events shall constitute a default by under this Agreement. If no cure period is provided below, such default shall be deemed an Event of Default by Service Provider immediately upon its occurrence. If a cure period is provided below, such default shall mature into an Event of Default if not cured within the indicated cure period~~, subject to Section 7 below~~.

1. Service Provider's application for, or consent (by admission of material allegations of a petition or otherwise) to, the appointment of a receiver, trustee or liquidator for Service Provider or for all or substantially all of its assets, or its authorization of such application or consent, or the commencement of any proceedings seeking such appointment without such authorization, consent or application, which proceedings continue undismissed or unstayed for a period of sixty (60) Days from inception.

Cure Period: None.

2. Service Provider's authorization or filing of a voluntary petition in bankruptcy or application for or consent (by admission of material allegations of a petition or otherwise) to the application of any bankruptcy, reorganization, readjustment of debt, insolvency, dissolution, liquidation or other similar law of any jurisdiction or the institution of such proceedings against Service Provider without such authorization, application or consent, which proceedings remain undismissed or unstayed for sixty (60) Days from its inception or which result in adjudication of bankruptcy or insolvency within such time.

Cure Period: None.

3. Service Provider's assignment of this Agreement not permitted by Section 11.2.

Cure Period: None.

4. Any representation or warranty by Service Provider in this Agreement that has a Material Adverse Effect on Service Provider's ability to perform this Agreement is proven to have been false in any material respect when made.

Cure Period: None.

5. Service Provider's failure to establish and, once established, maintain the Security Fund as and in the amounts required under Article 6.

Cure Period: Five (5) Business Days after Company provides notice of Service Provider's failure.

6. Service Provider's failure to obtain and maintain insurance in scope and amounts required under Article ~~16~~10.

Cure Period: Five (5) Business Days after Company provides notice of Service Provider's failure.

7. Service Provider's failure to make any payment to Company as and when required by this Agreement, including Liquidated Damages, Actual Damages, and any required indemnification.

Cure Period: Ten (10) Business Days after Company provides notice that the amount is overdue.

8. Any representation or warranty by Service Provider in this Agreement that has a Material Adverse Effect on Service Provider's ability to perform this Agreement ceases to remain true during the Term, other than due to a change of law.

Cure Period: None.

~~8.~~

9. Subject to Section 7.2, failure for Services Provider to deliver the NWA Services when called upon

Cure Period: None.

10. If, at any time during the Term of this Agreement the Company learns that the equipment necessary to deliver the NWA Services was not actually or properly installed, or no longer meets the NWA Services Guarantee,

Cure Period: None.

11. The breach by Service Provider of the Interconnection Agreement, if any, which breach (i) materially interferes with Service Provider's delivery of the NWA Services or Company's ability to accept or receive such NWA Services, and/or (ii) otherwise has a Material Adverse Effect on Company.

Cure Period: Thirty (30) Days from the breach or the cure period allowed by the Interconnection Agreement (whichever is longer)

(B) *Remedies for Default*. In connection with any default by Service Provider under this Section 7.1(whether or not cured by Service Provider, Company may:

1. Subject to Section 7.2, obtain Liquidated Damages as provided for in this Agreement; and,
2. Seek Actual Damages in such amounts and on such basis for the default as authorized by this Agreement; and,
3. Offset against any payments due to Service Provider, any Actual Damages and other amounts due from Service Provider; and
4. Draw any Liquidated and Actual Damages and other amounts due from Service Provider, from the Security Fund.

(C) *Termination for Event of Default*. Upon and at any time following an Event of Default by Service Provider under this Section 7.1, in addition to its rights under

Formatted: Body Text

Formatted: Underline

Formatted: Underline

Section 7.1 above, Company may terminate this Agreement immediately upon notice to Service Provider, without penalty or further obligation to Service Provider. In connection with any such termination, Company may collect from Seller all Actual Damages arising from such Event of Default through the Scheduled Termination Date.

7.2 Service Provider's Default for Underperformance and Non-Performance. Service Provider acknowledges that Company's agreement to make Payment to Service Provider is contingent upon the truth and accuracy of Service Provider's NWA Services Guarantee, its other representations and warranties herein, and the performance by Service Provider of its obligations hereunder. The Parties acknowledge and agree that the amount of damages that Company would suffer as a result of a NWA Services Guarantee Breach would be substantial but difficult or impossible to determine, that otherwise obtaining an adequate remedy is inconvenient due, among other things, to the timeframes and processes associated with planning and constructing electric distribution infrastructure, and that the Liquidated Damages constitute a reasonable approximation of the harm or loss. The Parties further acknowledge and agree that the Liquidated Damages provided for herein are not punitive nor in the nature of a penalty.

(A) Upon Service Provider's first failure to achieve at least ninety percent (90%) of the Demand Reduction for the required duration as provided in Exhibit A –NWA Services during a Peak Demand Event ("NWA Services Guarantee Breach"), then Service Provider will be obligated (without limiting Company's other rights and remedies under this Agreement, at law or in equity), immediately upon the occurrence of such ~~Delivery of~~ NWA Services Guarantee Breach, to pay to Company by check or wire transfer of immediately available funds the applicable Liquidated Damages equal to the total amount payable by Company to Service Provider for the Commercial Operation Year in which the first NWA Services Guarantee Breach occurred, which amount the Parties agree is specifically intended to be a Liquidated Damages amount and not a penalty.

(B) Upon Service Provider's second NWA Services Guarantee Breach, Company shall be entitled to terminate this Agreement in whole or in part, effective upon notice, and shall be relieved of any responsibility to make any further Payments (Service Provider hereby releasing and forever discharging the Company from any and all losses, liabilities, claims, costs and expenses resulting from Service Provider's failure to receive such incentive payments in accordance with the foregoing).

7.3 Default by Company: General.

(A) *Events*. Any of the following events shall constitute a default under this Agreement. If no cure period is provided below, such default shall be deemed an Event of Default by Company immediately upon its occurrence. If a cure period is provided below, such default shall mature into an Event of Default if not cured within the indicated cure period~~, subject to Section 7 below~~.

1. Company's application for, or consent (by admission of material allegations of a petition or otherwise) to, the appointment of a receiver, trustee or liquidator for Company or for all or substantially all of its assets, or its authorization of

such application or consent, or the commencement of any proceedings seeking such appointment without such authorization, consent or application, which proceedings continue undismissed or unstayed for a period of sixty (60) Days from inception.

Cure Period: None.

2. Company's authorization or filing of a voluntary petition in bankruptcy or application for or consent (by admission of material allegations of a petition or otherwise) to the application of any bankruptcy, reorganization, readjustment of debt, insolvency, dissolution, liquidation or other similar law of any jurisdiction or the institution of such proceedings against Company without such authorization, application or consent, which proceedings remain undismissed or unstayed for sixty (60) Days from its inception or which result in adjudication of bankruptcy or insolvency within such time.

Cure Period: None.

3. Company's assignment of this Agreement not permitted by Section 11.2.

Cure Period: None.

4. Any representation or warranty by Company in this Agreement that has a Material Adverse Effect on Company's ability to perform this Agreement is proven to have been false in any material respect when made.

Cure Period: None.

5. Company's failure to make any payment to Service Provider as and when required by this Agreement, including Actual Damages, and any required indemnification.

Cure Period: Ten (10) Business Days after Service provider provides notice that the amount is overdue.

6. Any representation or warranty by Company in this Agreement that has a Material Adverse Effect on Company's ability to perform this Agreement ceases to remain true during the Term, other than due to a change of law.

(B) The Parties confirm that the express remedies and measures of damages provided in this Agreement satisfy the essential purposes hereof. If no remedy or measure of damages is expressly herein provided, the obligor's liability shall be limited to all direct damages proximately caused by such default ("Actual Damages") incurred by the non-defaulting Party. **Neither Party shall be liable to the other Party for consequential, incidental, punitive, exemplary, special, treble, equitable or indirect damages, regardless of whether the relevant cause of action arises from statute, tort or contract** (except to the extent expressly provided herein); *provided*, *however*, that if either Party is held liable to a third party for such damages and the Party held liable for such damages is entitled to indemnification from the other Party hereto, the indemnifying

Party shall be liable for, and obligated to reimburse the indemnified Party for all such damages.

(C) To the extent damages required to be paid hereunder are liquidated, the Parties acknowledge that actual damages would be substantial but difficult or impossible to determine, that otherwise obtaining an adequate remedy is inconvenient, and that the liquidated damages constitute a reasonable approximation of the harm or loss.

7.4 Cumulative Remedies. Except as explicitly provided to the contrary in this Agreement, each right or remedy of the Parties provided for in this Agreement shall be cumulative of and shall be in addition to every other right or remedy provided for in this Agreement, and the exercise of one or more or the rights or remedies provided for herein shall not preclude the simultaneous or later exercise by such Party of any other rights or remedies provided for herein.

7.5 Duty to Mitigate. Each Party shall use Commercially Reasonable Efforts to mitigate any damages it may incur as a result of a default by the other Party under this Agreement.

Article 8 - Dispute Resolution

8.1 Disputes. The Company will have sole discretion to determine the final resolution of any and all issues pertaining to this Agreement, including, but not limited to, project eligibility, energy savings, peak Demand Reduction, and Payment amounts payable.

8.2 Governing Law. The interpretation and performance of this Agreement, and all actions related hereto (whether sounding in contract, tort or otherwise), shall be governed and construed in accordance with the laws of the State of Colorado, exclusive of conflict of laws principles.

8.3 Venue. The Parties submit to the exclusive jurisdiction of the state courts of the State of Colorado for purposes of resolving any dDispute hereunder. Venue for any court proceedings shall lie exclusively in the Colorado District Court for the City and County of Denver or, if jurisdictionally available, the U.S. District Court for the District of Colorado.]

8.4 Waiver of Jury Trial. **Service Provider and Company each hereby knowingly, voluntarily and intentionally waive any rights they may have to a trial by jury** in respect of any litigation based hereon, or arising out of, under, or in connection with, this Agreement or any course of conduct, course of dealing, statements (whether oral or written) or actions of Service Provider and Company related hereto and expressly agree to have any dDisputes be adjudicated by a judge of the court having jurisdiction, without a jury.

Article 9 - Representations and Warranties

9.1 Each Party hereby represents and warrants to the other as follows, which representations and warranties shall be deemed to be repeated, if applicable, by each Party throughout the Term:

(A) Such Party is a valid separate legal entity, duly organized, validly existing and in good standing under Applicable Law. It is qualified to do business in the State of Colorado and it has all requisite power and authority to conduct its business, to own its properties, and to execute, deliver, and perform its obligations under this Agreement.

(B) The Party's execution, delivery, and performance of all of its obligations under this Agreement have been duly authorized by all necessary organizational action, and do not and will not:

1. require any consent or approval by any governing corporate or management body, other than that which has been obtained and is in full force and effect (evidence of which shall be delivered to the other Party upon its request);

2. violate any Applicable Law, the violation of which could have a Material Adverse Effect on the representing Party's ability to perform its obligations under this Agreement;

3. result in a breach or constitute a default under the representing Party's formation documents, bylaws or equivalent, or under any agreement relating to its management or affairs or any indenture or loan or credit agreement, or any other agreement, lease, or instrument to which it is a party or by which it or its properties or assets may be bound or affected, the breach or default of which could reasonably be expected to have a Material Adverse Effect on the representing Party's ability to perform its obligations under this Agreement; or

4. result in, or require the creation or imposition of any mortgage, deed of trust, pledge, lien, security interest, or other charge or encumbrance of any nature upon or with respect to any of the assets or properties of the representing Party now owned or hereafter acquired, the creation or imposition of which could reasonably be expected to have a Material Adverse Effect on the representing Party's ability to perform its obligations under this Agreement.

(C) This Agreement is a valid and binding obligation of the representing Party.

(D) The execution and performance of this Agreement will not conflict with or constitute a breach or default under any contract or agreement of any kind to which the representing Party is a party or any judgment, order, or Applicable Law, applicable to it or its business.

Article 10 - Indemnification and Insurance

10.1 Indemnification.

(A) To the fullest extent permitted by law, Service Provider shall indemnify, defend and hold harmless Company, and its parent company, subsidiaries, affiliates and their respective shareholders, officers, directors, employees, agents, representatives, successors and assigns (collectively, the "Indemnified Parties"), from and against any and all claims, actions, suits, proceedings, losses, liabilities, penalties, fines, damages, costs or expenses, including without limitation reasonable attorneys' fees ("Claim"), resulting from (a) any breach of the representations, warranties, covenants and obligations of Service Provider under this Agreement, (b) any act or omission of Service Provider, whether based upon Service Provider's negligence, strict liability or otherwise, in connection with the performance of this Agreement, or (c) any third party claims of any kind, whether based upon negligence, strict liability or otherwise, arising out of or connected in any way to Service Provider's performance or nonperformance under this Agreement.

(B) If any Claim is brought against the Indemnified Parties, Service Provider shall assume the defense of such Claim, with counsel reasonably acceptable to the Indemnified Parties, unless in the opinion of counsel for the Indemnified Parties a conflict of interest between the Indemnified Parties and Service Provider may exist with respect to such Claim. If a conflict precludes Service Provider from assuming the defense, then Service Provider shall reimburse the Indemnified Parties on a monthly basis for the Indemnified Parties' reasonable defense costs through separate counsel of the Indemnified Parties' choice. If Service Provider assumes the defense of the Indemnified Parties with acceptable counsel, the Indemnified Parties, at their sole option and expense, may participate in the defense with counsel of their own choice without relieving Service Provider of any of its obligations hereunder.

(C) Service Provider's obligation to indemnify the Indemnified Parties shall survive the expiration or termination of this Agreement.

10.2 Insurance.

(A) Service Provider shall maintain during the term of this Agreement, at its own expense, employers' liability and workers' compensation insurance providing benefits in accordance with the laws and regulations of the State of Colorado.

(B) Service Provider shall maintain, during the term of the Agreement, at its own expense commercial general liability insurance, including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per

occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

(C) Service Provider shall maintain, during the term of the Agreement, at its own expense comprehensive automobile liability insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

(D) Service Provider shall maintain, during the term of the Agreement, at its own expense excess public liability insurance over and above the employers' liability, commercial general liability, and comprehensive automobile liability insurance coverage, with a minimum combined single limit of Ten Million Dollars ($10,000,000) per occurrence/Ten Million Dollars ($10,000,000) aggregate.

(E) The insurance required by this Section 10.2 shall, by endorsement to the policy or policies, provide for thirty (30) ~~calendar d~~Days' written notice to Public Service prior to cancellation, termination, alteration, or material change of such insurance.

(F) The commercial general liability insurance, comprehensive automobile Insurance and excess public liability insurance policies shall name the Company, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees as additional insureds.

(G) The commercial general liability insurance, comprehensive automobile liability insurance, and excess public liability insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies or self-insurance maintained by Public Service.

(H) The commercial general liability insurance, comprehensive automobile liability insurance, and excess public liability insurance policies, if written on a claims first made basis, shall be maintained in full force and effect for two (2) years after termination of this Agreement, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Company.

(I) The requirements contained herein as to the types and limits of all insurance to be maintained are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Service Provider.

(J) Evidence of the insurance required in this Section 10.2 shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by Public Service.

Formatted: Underline

(K) If Service Provider is self-insured with an established record of self-insurance, the Customer may comply with the following in lieu of Section 10.2 (B) – (L):

Formatted: Underline

1. Service Provider shall provide to Public Service, at least thirty (30) days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under Section 10.2(B) – (D).

2. If Service Prover ceases to self-insure to the level required hereunder, or if the Service Provider is unable to provide continuing evidence of its ability to self-insure, Service Provider agrees to immediately obtain the coverage required under Section 10.2(B) – (L).

(L) Service Provider shall provide Public Service certificates of insurance evidencing the requisite coverage and provisions prior to the Required In-Service Date. Afterwards, Public Service may periodically request proof of current insurance coverage in order to verify compliance with the requirements of this Section 10.2. Upon receipt of any such request, the Service Provider shall provide certificates of insurance evidencing the requisite coverage and provisions. Failure of Service Provider to provide timely evidence of proper insurance shall constitute a material breach and may result in ~~Early Termination~~termination of this Agreement pursuant to Section 3.~~32~~.

(M) Failure of Service Provider or Public Service to enforce or maintain the minimum levels of insurance does not relieve Service Provider from its obligation to maintain such levels of insurance or relieve Service Provider of any liability.

(N) The Parties agree to promptly notify each other, in writing, of any personal injury or damage to property apparently or actually related to the provision of services pursuant to this Agreement.

Article 11 - Miscellaneous

11.1 Notices.

(A) For coordination purposes, any notice or other communication (but not including invoices or routine correspondence relating to performance by Service Provider) given under this Agreement to any party must be in writing and must be sent by hand or overnight mail service, or registered or certified United States mail, return receipt requested, to the attention of the other Party at the addresses noted in Exhibit F – Notices and Contact Information.

(B) The Parties recognize the need for accurate communications between them. Each Party consents to the recording of telephone conversations between their employees and representatives, related to the performance and administration of this Agreement.

11.2 Non-Assignment. Neither this Agreement, nor any part or the whole of any project arising hereunder, and to include no part or the whole of any work associated with any project, may be assigned, delegated, subcontracted, or otherwise transferred by Service Provider without the prior written approval of the Company in each case. Service

Formatted: Underline

Formatted: Underline

Formatted: Underline

Formatted: Underline

Provider shall give Company at least ninety (90) D-days' notice for any planned assignment of this Agreement or a project arising hereunder.

11.3 Severability. In the event any of the terms, covenants, or conditions of this Agreement, its Exhibits, or the application of any such terms, covenants, or conditions, shall be held invalid, illegal, or unenforceable by any court or administrative body having jurisdiction, all other terms, covenants, and conditions of the Agreement and their application not adversely affected thereby shall remain in force and effect; *provided*, *however*, that Company and Service Provider shall negotiate in good faith to attempt to implement an equitable adjustment in the provisions of this Agreement with a view toward effecting the purposes of this Agreement by replacing the provision that is held invalid, illegal, or unenforceable with a valid provision the economic effect of which comes as close as possible to that of the provision that has been found to be invalid, illegal or unenforceable.

11.4 Complete Agreement; Amendments. The terms and provisions contained in this Agreement constitute the entire agreement between Company and Service Provider with respect to the NWA Services and shall supersede all previous communications, representations, or agreements, either verbal or written, between Company and Service Provider with respect to the NWA Services. Any amendment of this Agreement, or any waiver of any provision hereof, shall be evidenced by a writing signed by the Parties to be bound thereby.

11.5 Waiver. The failure of either Party to enforce or insist upon compliance with or strict performance of any of the terms or conditions of this Agreement, or to take advantage of any of its rights hereunder, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect.

11.6 Headings. Captions and headings used in this Agreement are for ease of reference only and do not constitute a part of this Agreement.

11.7 Counterparts. This Agreement may be executed in counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

11.8 Exhibits. Either Party may change the information in Exhibit F – Notices and Contact Information at any time by notice without the approval of the other Party. All other Exhibits may be changed to the extent allowed by specific provisions of this Agreement or with the mutual consent of both Parties.

Formatted: Underline

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the date first set forth above.

Service Provider:

By: _____

Company:

Public Service Company of Colorado

By: _____

EXHIBIT A

NWA SERVICES

(All sections of this form must be completed and attached to a fully executed Non-Wires Alternative Services Agreement)

Service Provider Information

Name of Service Provider _____

Mailing Address _____

(Street number and name) (Suite number)

_____

(City, state, zip code)

Nature of Business _____

Contact Person _____ Title _____

Email _____ Phone _____

Non-Wires Alternative Services Details

Project Name _____

Project Site Location _____

NWA Location _____

Metering Point _____

NWA Category: *(check all that apply)*

☐Demand Response ☐Energy Efficiency ☐Energy Storage

☐Distributed Generation ☐Other (*describe in Summary*)

NWA Services Provided _____

Proposed NWA Services Summary _____

_____

_____

_____

_____

Methodology for Calling on NWA Services (<u>if applicable</u>)

_____

_____

_____

EXHIBIT B

NWA SERVICES GUARANTEE

[To be inserted]

Formatted: Font: Bold

Formatted: Font: Italic

Formatted: Body Text, Centered

EXHIBIT C

NWA SERVICES PAYMENT RATE

NWA Services Payment Rate

In exchange for the NWA Services described above, and subject to the terms and conditions set forth in the Agreement, the Company agrees to pay Service Provider the following in each ~~Year~~ Commercial Operation Year of the Agreement, beginning in the Commercial Operation Year in which the Required In-Service Date occurs:

Required In-Service Date _____

Commercial Operation Year

1 $_____

2 $_____

3 $_____

4 $_____

5 $_____

Formatted: Font: Bold

EXHIBIT D

FORM OF LETTER OF CREDIT

[LETTERHEAD OF ISSUING BANK]

Irrevocable Standby Letter of Credit No: _____

Date of Issuance: _____

Beneficiary: [Public Service Company of Colorado]

Initial Expiration Date: [Must be at least one year after date of issuance]

Applicant:

As the Issuing Bank ("Issuer"), we, [Name of Issuing Bank], hereby establish this irrevocable Standby Letter of Credit No. ____ (this "Letter of Credit") in favor of the above-named beneficiary ("Beneficiary") for the account of the above-named applicant ("Applicant") in the amount of US$ _____ (_____ Million U.S. Dollars).

Beneficiary may draw all or any portion of this Letter of Credit at any time and from time to time, and Issuer will make funds immediately available to Beneficiary upon presentation of Beneficiary's draft(s) at sight in substantially the form attached hereto as Exhibit "A" ("Sight Draft"), drawn on Issuer and accompanied by this Letter of Credit. All Sight Drafts must be signed on behalf of Beneficiary, and the signator must indicate his or her title or other official capacity. No other documents will be required to be presented. Issuer will effect payment under this Letter of Credit within twenty-four (24) hours after presentment of any Sight Draft. Payment shall be made in U.S. Dollars with Issuer's own funds in immediately available funds.

Issuer will honor any Sight Draft presented in substantial compliance with the terms of this Letter of Credit at the Issuer's letterhead office, the office located at _____ or any other full service office of the Issuer on or before the above-stated expiration date, as such expiration date may be extended hereunder. Partial and multiple draws and presentations are permitted on any number of occasions. Following any partial draw, Issuer will endorse this Letter of Credit and return the original to Beneficiary.

This Letter of Credit is issued pursuant to the provisions of that certain Non-Wires Alternative Services Agreement ~~Solar Generating and Battery Storage Energy Purchase Agreement~~ between Beneficiary and Applicant dated as of _____, 20___ (as the same may have been or may be amended from time to time, the "~~PPA~~Agreement"). Notwithstanding any reference in this Letter of Credit to the ~~PPA~~ Agreement or any other documents, instruments or agreements, or references in the ~~PPA~~ Agreement or any other documents, instruments or agreements to this Letter of Credit, this Letter of Credit contains the entire agreement between Beneficiary and Issuer relating to the obligations of Issuer hereunder.

This Letter of Credit will be automatically extended each year without amendment for a period of one (1) year from the expiration date hereof, as extended, unless at least thirty

Formatted: Font: Bold

Formatted: Font: Italic

(30) days prior to the expiration date, Issuer notifies Beneficiary by registered or certified mail that it elects not to extend this Letter of Credit for such additional period. Notice of non-extension will be given by Issuer to Beneficiary at Beneficiary's address set forth herein or at such other address as Beneficiary may designate to Issuer in writing at Issuer's letterhead address.

This Letter of Credit is freely transferable by Beneficiary in whole or in part, and the number of transfers is unlimited. Issuer shall effect any transfers immediately upon presentation to Issuer of this Letter of Credit and a completed written transfer request substantially in the form attached hereto as Exhibit "B." Such transfer will be effected at no cost to Beneficiary. Any transfer fees assessed by Issuer will be payable solely by Applicant, and the payment of any transfer fees will not be a condition to the validity or effectiveness of the transfer of this Letter of Credit.

Issuer waives any rights it may have, at law or otherwise, to subrogate to any claims which Beneficiary may have against Applicant or Applicant may have against Beneficiary.

This Letter of Credit is subject to the uniform customs and practice for documentary credits (2007 Revision), International Chamber of Commerce publication No. 600 (the "UCP"), except to the extent that the terms hereof are inconsistent with the provisions of the UCP, including but not limited to Articles 14(b) and 36 of the UCP, in which case the terms of this Letter of Credit shall govern. With respect to Article 14(b) of the UCP, Issuer shall have a reasonable amount of time, not to exceed three (3) banking days following the date of Issuer's receipt of documents from Beneficiary (to the extent required herein), to examine the documents and determine whether to take up or refuse the documents and to inform Beneficiary accordingly.

In the event of an act of God, riot, civil commotion, insurrection, war or any other cause beyond Issuer's control that interrupts Issuer's business and causes the place for presentation of this Letter of Credit to be closed for business on the last day for presentation, the expiry date of this Letter of Credit will be automatically extended without amendment to a date thirty (30) calendar days after the place for presentation reopens for business.

ISSUER:

By: _____
Authorized Signature

EXHIBIT "A"
TO LETTER OF CREDIT

SIGHT DRAFT

Draft Number _____
$_____

At sight, pay to the order of [Name of Beneficiary to be inserted], the amount of USD $_____ (_____ and 00/100ths U.S. Dollars).

Value received and charged to the account of: [Name of Issuer and address]. Drawn under [Name of Issuer to be inserted] Standby Letter of Credit No. _____.

Dated: _____ [Public Service Company of Colorado]

By: _____
[name and title]

Account: [Applicant to be inserted]

EXHIBIT "B"
TO LETTER OF CREDIT

FORM OF TRANSFER REQUEST

Irrevocable Standby Letter of Credit No. _____

Current Beneficiary:	Applicant:
_____	_____
_____	_____
_____	_____
_____	_____

To: [Name of Issuer] ("Issuer")

The undersigned, as the current "Beneficiary" of the above-referenced Letter of Credit, hereby requests that you reissue the Letter of Credit in favor of the transferee named below [insert transferee name and address below]:

_____
_____
_____
_____

From and after the date this transfer request is delivered to Issuer, the transferee shall be the "Beneficiary" under the Letter of Credit for all purposes and shall be entitled to exercise and enjoy all of the rights, privileges and benefits thereof.

Dated: _____ [Public Service Company of Colorado]

By: _____
Name: _____
Title: _____

[Notary Acknowledgement]

To be signed by a person purporting to be an authorized representative of Beneficiary and indicating his or her title or other official capacity, and acknowledged by a notary public.

EXHIBIT E

~~ILLUSTRATIVE~~ FORM OF GUARANTY

GUARANTY

This Guaranty is executed and delivered as of this ____ day of _____, 20__ by _____, a _____ [corporation] ("Guarantor"), in favor of [Public Service Company of Colorado] ("Company"), in connection with the performance by _____, a _____ [limited liability company] ("Seller") of a Non-Wires Alternative Services Agreement ~~Solar Generating and Battery Storage Energy Purchase Agreement~~ dated _____, 20____ between Seller and Company (the "~~PPA~~NWA Agreement").

- RECITALS ~~-~~ -

A. Seller proposes to provide Non-Wires Alternative Services to the Company~~construct, own and operate a solar power electric generation and Battery Storage System having a Solar Nameplate Capacity of approximately _____ MW and a Battery Storage System Nameplate Capacity of approximately _____ MW located in _____ County, _____ (the "Facility")~~.

B. Seller and Company have entered into the ~~PPA~~ NWA Agreement ~~for the purchase and sale of electrical energy from the Facility~~ on the terms and conditions set forth therein.

C. Seller is controlled by Guarantor. Guarantor expects to derive substantial benefits from the performance of the ~~PPA~~ NWA Agreement by Seller and Company. To induce Company to enter into and continue the ~~PPA~~ NWA Agreement~~and to consummate the purchase and sale of electrical energy contemplated by the PPA~~, Guarantor has agreed to guarantee the obligations of Seller as provided in this Guaranty.

NOW, THEREFORE, in consideration of the foregoing, Guarantor agrees as follows:

- AGREEMENT -

1. Guaranty. Subject to the provisions of this Guaranty, Guarantor hereby absolutely, irrevocably, unconditionally, and fully guarantees to Company the due, prompt, and complete observance, performance, and discharge of each and every payment obligation of Seller under the ~~PPA~~NWA Agreement, whether incurred before or after the date of delivery of this Guaranty (the "Obligations"). This is a guaranty of payment, not of collection, and as such, Company shall not be required to institute, pursue, or exhaust any remedies against Seller before instituting suit, obtaining judgment, and executing thereon against Guarantor under this Guaranty. This Guaranty shall survive termination of the ~~PPA~~ NWA Agreement to the extent necessary to enforce and complete the rights, duties and obligations of Company and Seller thereunder.

Formatted: Font: Bold

2. Maximum Liability. Notwithstanding anything herein to the contrary, Guarantor's maximum liability under this Guaranty shall be limited to _____ dollars (US$_____) plus costs of collection under Section 10 below.

3. Rights of Company. Guarantor hereby grants to Company, in Company's discretion and without the need to notify or obtain any consent from Guarantor, and without termination, impairment, or any other effect upon Guarantor's duties hereunder, the power and authority from time to time:

(a) to renew, compromise, extend, accelerate, or otherwise change, substitute, supersede, or terminate the terms of performance of any of the Obligations, in each case in accordance with the ~~PPA~~NWA Agreement;

(b) to grant any indulgences, forbearances, and waivers, on one or more occasions, for any length of time, with respect to Seller's performance of any of the Obligations; and

(c) to accept collateral, further guaranties, and/or other security for the Obligations, and, if so accepted, then to impair, exhaust, exchange, enforce, waive, or release any such security.

4. Performance. If any of the Obligations are not performed according to the tenor thereof, and any applicable notice and cure period provided by the ~~PPA~~ NWA Agreement has expired ("Default"), Guarantor shall immediately upon receipt of written demand by Company (a) perform or cause Seller to perform the Obligation in Default, and (b) pay, reimburse, and indemnify Company against any liabilities, damages, and related costs (including attorneys' fees) incurred by Company as a result thereof, all in such manner and at such times as Company may reasonably direct.

5. Satisfaction. Satisfaction by Guarantor of any duty hereunder incident to a particular Default or the occurrence of any other Default shall not discharge Guarantor except with respect to the Default satisfied, it being the intent of Guarantor that this Guaranty be continuing until such time as all of the Obligations have irrevocably been discharged in full, at which time this Guaranty shall automatically terminate. If at any time the performance of any Obligation by Seller or Guarantor is rescinded or voided under the federal Bankruptcy Code or otherwise, then Guarantor's duties hereunder shall continue and be deemed to have been automatically reinstated, restored, and continued with respect to that Obligation, as though the performance of that Obligation had never occurred, regardless of whether this Guaranty otherwise had terminated or would have been terminated following or as a result of that performance.

6. Notice of Acceptance. Guarantor waives and acknowledges notice of acceptance of this Guaranty by Company.

7. Waivers by Guarantor. Guarantor hereby waives and agrees not to assert or take advantage of:

(a) all set-offs, counterclaims, and, subject to Section 4 above, all presentments, demands for performance, notices of non-performance, protests, and notices of every kind that may be required by Applicable Laws;

(b) any right to require Company to proceed against Seller or any other person, or to require Company first to exhaust any remedies against Seller or any other person, before proceeding against Guarantor hereunder;

(c) any defense based upon an election of remedies by Company;

(d) any duty of Company to protect or not impair any security for the Obligations;

(e) the benefit of any laws limiting the liability of a surety;

(f) any duty of Company to disclose to Guarantor any facts concerning Seller, the ~~PPA~~ NWA Agreement~~or the Facility~~, or any other circumstances, that would or allegedly would increase the risk to Guarantor under this Guaranty, whether now known or hereafter learned by Company, it being understood that Guarantor is capable of and assumes the responsibility for being and remaining informed as to all such facts and circumstances; and

(g) until all Obligations in Default have been fully paid and/or performed, any rights of subrogation, contribution, reimbursement, indemnification, or other rights of payment or recovery for any payment or performance by it hereunder. For the avoidance of doubt, if any amount is paid to Guarantor in violation of this provision, such amount shall be held by Guarantor for the benefit of, and promptly paid to, Company.

8. Cumulative Remedies. The rights and remedies of Company hereunder shall be cumulative and not alternative to any other rights, powers, and remedies that Company may have at law, in equity, or under the ~~PPA~~NWA Agreement. The obligations of Guarantor hereunder are independent of those of Seller and shall survive unaffected by the bankruptcy of Seller. Company need not join Seller in any action against Guarantor to preserve its rights set forth herein.

9. Representations and Warranties. Guarantor represents and warrants to Company as follows:

(a) Guarantor is a corporation, duly organized, validly existing, and in good standing under the laws of the state of its incorporation. Seller is a direct or indirect wholly-owned subsidiary of Guarantor. Guarantor has all necessary corporate power and authority to execute and deliver this Guaranty and to perform its obligations hereunder.

(b) The execution, delivery and performance of this Guaranty has been duly and validly authorized by all corporate proceedings of Guarantor and is not in violation of any law, judgment of court or government agency~~.~~. This Guaranty has been duly and validly executed and delivered by Guarantor and constitutes a legal, valid and

binding obligation of Guarantor, enforceable against Guarantor in accordance with its terms.

10. Collection Costs. Guarantor shall pay to Company, upon demand, and in addition to the maximum liability set forth in Section 2 hereof, all reasonable attorneys' fees and other expenses which Company may expend or incur in enforcing the Obligations against Seller and/or enforcing this Guaranty against Guarantor, whether or not suit is filed, including, without limitation, all attorneys' fees, and other expenses incurred by Company in connection with any insolvency, bankruptcy, reorganization, arrangement, or other similar proceedings involving Seller that in any way affect the exercise by Company of its rights and remedies hereunder.

11. Severability. Should any one or more provisions of this Guaranty be determined to be illegal or unenforceable, all other provisions nevertheless shall be effective.

12. Waiver or Amendment. No provision of this Guaranty or right of Company hereunder can be waived, nor can Guarantor be released from Guarantor's duties hereunder, except by a writing duly executed by Company. This Guaranty may not be modified, amended, revised, revoked, terminated, changed, or varied in any way whatsoever except by the express terms of a writing duly executed by Company.

13. Successors and Assigns. This Guaranty shall inure to the benefit of and bind the successors and assigns of Company and Guarantor.

14. Governing Law. This Guaranty shall be governed by and construed in accordance with the law of the State of [*insert home state of Company*] without regard to the principles of conflicts of law thereof. Venue for any dispute hereunder shall be as set forth in ~~Section 13.5 of~~ the ~~PPA~~NWA Agreement.

15. Notices. All notices, requests, claims, demands, and other communications hereunder shall be in writing and shall be given (and shall be deemed to have been duly given upon receipt) by delivery in the manner contemplated by the NWA Agreement~~PPA~~, addressed as follows:

(a) *if to Company*: as provided in the ~~PPA~~NWA Agreement

(b) *if to Guarantor*: _____
_____
_____
Attn:

with a copy to: _____
_____
_____
Attn:

or to such other address (es) as the person to whom notice is given may have previously furnished to the others in writing in the manner set forth above.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered to Company as of the day and year first above written.

[Name of Guarantor]

By:_____
Name:
Title:

STATE OF_____)
) ss.
COUNTY OF _____)

The foregoing instrument was acknowledged before me this _____ day of _____, 20___, by _____, as _____ of _____.

Witness my hand and official seal.

My commission expires: _____.

(S E A L)

_____
Notary Public

EXHIBIT F

NOTICES AND CONTACT INFORMATION

Formatted: Font: Bold

Appendix 4 - NWA Solicitation

Public Service Company of Colorado

Request for Proposal for Non-Wires Alternative Services

Issued:



Confidential between PSCo and Respondent

Contents

Confidential between PSCo and Respondent 2
1.0 Background Information on Public Service 4
2.0 Introduction 4
2.1 Description of Proposals Sought through this RFP 4
2.1.1 Minimum Requirements of the Proposal 5
2.1.2 Term 6
3.0 Proposal Content Requirements 6
3.1 Company Proposals 6
3.2 Proposal Format 6
3.3 Notice of Intent to Respond (NOIR) 9
3.4 Proposal Submission Deadline 9
3.5 Bid Evaluation Fee 9
4.0 Information Policy 10
5.0 Clarification of Proposals 10
6.0 Confidentiality 10
7.0 Addenda to RFP 11
8.0 Evaluation Process and Criteria 11
8.1 Evaluation Process 11
8.2 Evaluation Criteria 12
9.0 Response Timing and Information 12

Notice of Disclaimer

The information contained in this Request for Proposals ("RFP") for Non-Wires Alternatives for Public Service Company of Colorado ("Public Service" or "Company") has been prepared solely to assist Respondents (also referred to herein as "Bidder(s)" or "Respondent(s)") in deciding whether or not to submit a proposal. Public Service does not represent this information to be comprehensive or to contain all of the information that a Respondent may need to consider in order to submit a proposal. Public Service and its affiliates, employees, directors, officers, shareholders, customers, agents and consultants (collectively "Public Service Representatives") do not make, and will not be deemed to have made, any current or future representation, promise or warranty, express or implied, as to the accuracy, reliability or completeness of the information contained herein, or in any document or information made available to a Respondent, whether or not the aforementioned parties knew or should have known of any errors or omissions, or were responsible for their inclusion in, or omission from, this RFP.

Public Service reserves the right to modify, supplement or withdraw this RFP at any time, whether due to changes in law or otherwise, and including by issuing one or more addenda to this RFP during this solicitation, which addenda shall become a part of this RFP. No part of this RFP and no part of any subsequent correspondence by Public Service or Public Service Representatives shall be taken as providing legal, financial, or other advice or as establishing a contract or contractual obligation. This RFP has been prepared solely to solicit proposals and is not a contract offer, and this RFP is not binding on Public Service. Contractual obligations on the part of Public Service will arise only if definitive agreements are approved and executed by Public Service and a service provider. Public Service reserves the right to request from a Respondent information that is not explicitly detailed in this document, obtain clarification from Respondents concerning proposals, conduct contract development discussions with selected Respondents, and conduct discussions with members of the RFP evaluation team ("Evaluation Team"), the Independent Evaluator (if any), and other support resources.

Public Service will, in its sole discretion and without limitation, evaluate proposals and proceed in the manner Public Service deems appropriate, which may include deviation from the expected evaluation process, the waiver of any RFP requirements, and/or requests for additional information. Public Service reserves the right to reject any proposal (or portion of a proposal) received for failure to meet any criteria set forth in this RFP or otherwise and to accept proposals other than the lowest cost proposal. Public Service also may decline to enter into any agreement with any Bidder, terminate negotiations with any Bidder, or abandon the RFP process in its entirety at any time, for any reason and without notice thereof. Respondents that submit proposals agree to do so without legal recourse against Public Service for rejection of their proposals or for failure to execute an agreement for any reason. Public Service shall not be liable to any Respondent or other party in law or equity for any reason whatsoever for any acts or omissions arising out of or in connection with this RFP. By submitting its proposal, each Respondent waives any right to challenge any evaluation by Public

Service or the Public Service Representatives of its proposal. By submitting its proposal, each Respondent waives any right to challenge any determination of Public Service or the Public Service Representatives to select or reject its proposal. Each Respondent, in submitting its proposal, irrevocably agrees and acknowledges that it is making its proposal subject to and in agreement with the terms of this RFP.

Each Respondent shall be liable for all of its costs incurred to prepare, submit, respond or negotiate its proposal and any resulting agreement and for any other activity related thereto, and Public Service shall not be responsible for any of the Respondent's costs. Respondent whose proposal may be selected in response to this RFP acknowledge that it assumes full legal responsibility for the accuracy, validity, and legality of the work and services provided in conformance with this RFP.

1.0 Background Information on Public Service

Public Service is a regulated utility that serves electric and natural gas customers in the State of Colorado. It is one of the Xcel Energy utility operating companies. This RFP relates to Public Service's operation of its electric distribution grid. Public Service is seeking proposals that will provide reliable and cost-effective Non-Wires Alternatives services. Non-Wires Alternatives "means the strategic deployment of distributed energy resources by a utility or third part and associated control or aggregation of systems and technologies intended to cost-effectively defer or avoid the need for Major Grid Distribution Projects." 4 CCR 723-3 at Rule 3527(p). Major Grid Distribution Projects means planned, proposed, or potential construction, reconfiguring or upgrade of any electric distribution line, substation, or ancillary structure that meets certain criteria, including that it has an estimated cost of more than $2 million on the distribution grid or more than $3 million on both the transmission and distribution grids. Id. at Rule 3527(m). The specific Major Grid Distribution Projects for which Public Service is seeking possible Non-Wires Alternatives are listed on Attachment A along with the specific criteria for the services that would be necessary to defer or avoid each listed Major Grid Distribution Project.

2.0 Introduction

Public Service is seeking proposals for Non-Wires Alternatives services as outlined below.

2.1 Description of Proposals Sought through this RFP

Public Service invites proposals for Non-Wires Alternatives services described in this Section.

This RFP seeks Non-Wires Alternatives services that will allow the Company to cost effectively defer or avoid one or more of the Major Grid Distribution Project described in Attachment A. Each individual listed Major Grid Distribution Project is planned to address specific constraints in a specific area of the distribution system. To effectively defer or avoid the need for a Major Grid Distribution Project, Non-Wires Alternatives services must fully, cost effectively, and reliably address the requirements set forth in Attachment A for the Major Grid Distribution Project for which the proposal is offered. If Respondent seeks to propose Non-Wires Alternatives services for multiple

Major Grid Distribution Projects, it should do so by submitting separate proposals for each such project.

2.1.1 Minimum Requirements of the Proposal

At a minimum, the Respondent's Non-Wires Alternative services proposal must reliably and cost-effectively provide the ability to mitigate the underlying needs for the Major Grid Distribution Project described in Attachment A for which the proposal is offered as an alternative, so as to allow Public Service to defer or avoid the specified Major Distribution Grid Project. To be responsive, the proposal should be capable of addressing the specific constraints addressed by the Major Distribution Grid Project, including but not limited to time of day and amount of reduction, total annual hours when the services will or can be provided, and when services will and will not be available.

Public Service anticipates that most Non-Wires Alternatives will involve demand response programs, energy efficiency programs, energy storage services, distributed generation, or some combination thereof; however, this RFP is methodologically and technology agnostic (unless otherwise noted here, and approved by the Commission) and Proposals may involve one or more projects or programs. No particular methods or technologies are required and proposals wholly or partially involving new and innovative methods and/or technologies are welcome provided their reliability can be sufficiently demonstrated.

Respondents should note that with regard to proposals wholly or partially involving distributed generation and energy storage services, the Interconnection Procedures and Standards set forth at Rules 3850 to 3859 of the Public Utilities Commission of the state of Colorado's ("CPUC") Electric Rules (4 Code of Colorado Regulations 723-3) shall apply to any necessary interconnections. Respondents should be aware that Public Service manages the interconnection process through different functions of the Company or through its affiliates. To that end, the model contract attached as Attachment B contains a provision stating that any breach, dispute, or other issue related to Public Service's or its affiliates' performance under any Interconnection Agreement or other conduct by Public Service related to the Interconnection Procedures and Standards or an Interconnection Agreement shall not be considered a breach by Public Service of its obligation of good faith and fair dealing or any other statutory or common law requirement under an agreement with respect to the provision of Non-Wires Alternatives services and that a provider of Non-Wires Alternatives services waives any and all claims at equity or law related thereto. Likewise, the model contract provides that any breach, dispute, or other issue related to Public Service's performance of a contract for provision of Non-Wires Alternatives service or other conduct by Public Service related to this contract for provision of Non-Wires Alternatives services shall not be considered a breach by Public Service of its obligation of good faith and fair dealing or any other statutory or common law requirement under an Interconnection Agreement or the Interconnection Procedures and Standards and the model contract further provides that the provider of Non-Wires Alternatives Services agrees to waive any and all

claims at equity or law related thereto.

2.1.2 Term

As reflected in the model contract attached as Attachment B, Public Service contemplated that Non-Wires Alternatives services will be [insert] (X) years.

3.0 Proposal Content Requirements

This section outlines the content and format requirements for all proposals submitted in response to this RFP. Unless Public Service decides in its sole discretion to waive a particular requirement or requirements, proposals that do not include the information requested in this section will be ineligible for further evaluation. Public Service reserves the right to conduct any further due diligence they consider necessary to fully understand and evaluate proposals.

3.1 Company Proposals

Public Service and/or its affiliated Xcel Energy entities reserve the right to submit proposals in response to the RFP. If such proposals are submitted, the deadlines and requirements set forth herein shall be the same as for other Respondents, except that such a proposal need not provide proposed revisions to the model contract attached hereto as Attachment B. Any Public Service or affiliated entity personnel working on such a Company proposal may not communicate with the RFP Coordinator or persons affiliated with Public Service and/or Xcel Energy involved in evaluating proposals regarding this procurement or the Major Distribution Grid Project(s) except under the same terms and limitations set forth in this RFP as apply to all respondents. Any Public Service or affiliated entity personnel working on such a Company proposal shall not have access to non-public information regarding the Major Distribution Grid Project(s), the evaluation criteria, or this procurement beyond that provided in this RFP (and its attachments) except through use of the same procedures set forth in this RFP applicable to all Respondents.

3.2 Proposal Format

A complete proposal will include the following components:

1. Executive Summary.
2. Identification of the specific Major Grid Distribution Project for which the Respondent is proposing Non-Wires Alternatives services. If Respondent wishes to propose Non-Wires Alternatives for more than one of the Major Grid Distribution Projects listed on Attachment A, it should submit separate proposals for each such project.
3. Organizational information. Provide a description of your organization, including: legal name and any trade or brand name(s); organizational form; as applicable, list of principal shareholders, other business owners or joint venture participants and their respective percentage of participation; general experience; capabilities; and, references. The same information should be provided for any identified subcontractors, consultants, or joint venture members who will be involved in providing the proposed services.
4. Names and contact information for the person or persons who will serve as Respondent's primary contacts with regard to this RFP.

5. The *Curriculum Vitae(s)*'s of the key team members, including supplemental information such as client reference information and other materials that demonstrate each team members' qualifications. Key team members should include, at a minimum, those persons who will serve as primary contacts with Public Service, the person(s) who will manage provision of the proposed services, project manager(s), and, for any proposals that involve the construction and/or installation of equipment or facilities, any design professionals (including electrical engineers), construction project managers, and superintendents.
6. Proposed pricing for provision of the Non-Wires Alternatives services, including but not limited to any information regarding financial incentives that would be provided to any persons for hosting equipment or infrastructure or otherwise participating in or facilitating the Non-Wires Alternatives services, and information regarding whether any portion of the costs of any infrastructure or equipment used to provide the proposed Non-Wires Alternatives services would be paid for by host locations.
7. Any comments or proposed revisions to Public Service's model contract, attached hereto as Attachment B. If Proposer does have any proposed revisions, it should include both red-lined and clean versions of its proposed version with its proposal. In order to preserve the integrity of the process, all proposed revisions must be presented at this stage of the process and in this manner.
8. A description of Respondent's plans for equitable hiring and any subcontracting, including its planned efforts to ensure that persons from traditionally disadvantaged communities and businesses owned by persons from traditionally disadvantaged communities are given fair opportunities.
9. Information demonstrating that Respondent has the capacity to provide the Security Fund required by Article 7 of the model contract attached hereto as Attachment B.
10. Narrative Topics Discussion including:
    a. Identification of the proposed approach, methods, and technologies that will be used to provide the Non-Wires Alternatives services, including information and data sufficient to show that the proposed services can reliably address the constraints set forth in Attachment A that would otherwise require implementation of the Major Distribution Grid Project(s) in question. Such information should include annual availability and an 8,760 annual load curve for an average year during the [insert]-year term.
    b. Specific information and data regarding any ancillary services that would be provided by the proposed Non-Wires Alternatives services.
    c. Specific information regarding the location(s) where the proposed services will be provided, with sufficient granularity so as to allow Public Service to analyze the impact on particular feeders and transformers.
    d. Detailed description of Respondent's experience with its proposed methods, technologies, and approaches, and/or similar methods, technologies, and approaches, including the names and locations of specific projects, information and data regarding the results of such earlier projects, names and contact information for counterparties, and references.

e. Information demonstrating that any equipment, infrastructure, or facility design work shall be carried out by licensed professionals with specific and applicable experience.
f. Information demonstrating that construction or installation work, if any, shall be carried out by professional contractors with all necessary licenses and inspected by licensed and experienced design professionals.
g. Descriptions and locations of any key facilities, equipment, or assets that would be used to provide the proposed services, including, as applicable, information on proposed construction and/or manufacturing timelines, contracts, and proposed technical specifications.
h. Information demonstrating that any real property entitlements which may be necessary for provision of the proposed services have been obtained or are subject to options, purchase agreements, or other enforceable contractual arrangements.
i. A proposed timeline and schedule for implementation of the proposed services and information demonstrating the feasibility of the schedule and timeline.
j. Information regarding any licenses or permits which may be necessary for provision of the proposed services and details on whether such licenses or permits have been obtained and, if not, plans and timelines for efforts to obtain such licenses or permits.
k. Detailed information regarding all contractual arrangements related to energy efficiency and/or demand response programs, including the specific identities and locations of program participants, the load reductions associated each participant, contract terms related to the duration, timing, nature, and terms for load reduction, and information demonstrating that the program(s) in question involve contractual commitments to provide at least one hundred and twenty percent (125%) of the necessary load reduction at the location(s) in question.
l. Respondent must affirm it is not subject to, and does not expect to be subject to, any legal restrictions (contractual, regulatory, etc.) that would preclude it from performing the duties in its response to this RFP.
m. Respondent must disclose whether it has been suspended, debarred, or otherwise excluded from procurement by the Federal government or any state or local government.
n. If respondent is proposing services that will require any interconnection(s) with the distribution grid, information regarding the current status, if any, of projects in the interconnection queue.
o. Discussion of how Respondent contemplates that its proposed services could be measured, tested, and verified.

11. A Respondent may also provide any narrative, data, charts, tables, diagrams, or other materials in addition to those specifically called for herein, to the extent such additions are useful for clarity or completeness of the response.

3.3 Notice of Intent to Respond (NOIR)

Respondents who intend to submit a proposal are strongly encouraged to also submit a non-binding Notice of Intent to Respond by sending an email to the RFP Coordinator. Public Service requests that completed NOIR forms be emailed to the RFP Coordinator at the earliest date possible but no later than 4:00 P.M. Mountain Time on [insert date].

3.4 Proposal Submission Deadline

All proposals will be accepted until 4:00 P.M. Mountain Time on [insert date]. All proposals must be transmitted by email or by express, certified or registered mail, or hand delivered to the RFP Coordinator at following address:

[insert address]

Proposals received later than the submission deadline will be rejected and returned unopened, unless Public Service determines, at its sole discretion, to consider such proposals.

If Respondent submits a hard-copy of its proposal, the Respondent's organizational name and address must be clearly indicated on the exterior of the package containing the proposal. If Respondent submits via email, "Response to NWA RFP" and Respondent's organizational name should be included in the subject line.

3.5 Bid Evaluation Fee

All respondents are required to pay to the Company a bid evaluation fee with each proposal submitted; bid fees are determined by the nameplate capacity of the bid according to Table 1 below. Checks should be made out to "Public Service Company of Colorado" and must be included with the proposal if a hard copy proposal is submitted. If a proposal is submitted via email, the bid fee check should be separately sent by express, certified or registered mail, or hand delivered to the RFP Coordinator at the address set forth in Section 3.4 above. Bid evaluation fees are non-refundable.

Table 1. Bid Fees

MW Range	Bid Fee
>0.1 to 1 MW	$375
>1 to 2 MW	$750
>2 to 5 MW	$1,500
>5 to 10 MW	$3,000
>10 MW	$10,000

4.0 Information Policy

To obtain additional information about this RFP, Respondents may submit inquiries to the RFP Coordinator via email. Respondents should not attempt to acquire information through any other means from Public Service, Public Service Representatives, or the Independent Evaluator. The RFP Coordinator will maintain a log of all email inquiries and coordinate the preparation of written responses. Once a response is prepared, the RFP Coordinator will forward the response to the inquiring party. Public Service has established this information policy to ensure that Respondents have timely access to and knowledge about the bidding and evaluation process.

5.0 Clarification of Proposals

While evaluating proposals, Public Service and/or the Independent Evaluator may request clarification or additional information about any item in the proposal. Such requests will be sent via email to the contact persons for Respondents identified in the proposal, and Respondents are required to provide a written or electronic response within five business days, or Public Service may, at its sole discretion, deem the Respondent to be non-responsive and either suspend or terminate evaluation of the proposal. Respondents are encouraged to provide an alternate point of contact to ensure a timely response to clarification questions.

6.0 Confidentiality

Consistent with the E-mail transmitting the RFP, Public Service and Respondents agree to keep confidential: 1) the RFP; 2) those pages of the response to the RFP that Respondents specifically designate and clearly identify as containing confidential and proprietary information; and 3) information and documents exchanged between Public Service and Respondent during the course of the preparation of the response to the RFP and the response evaluation process that are specifically designated and clearly identified as containing confidential and proprietary information ("Confidential Information"). Public Service and Respondent shall only disclose the Confidential Information to those within their organizations with a need to know, to the Independent Evaluator, and, as noted below (and subject to the requirements set forth below), in filings with the Colorado Public Utilities Commission. In addition, such Confidential Information shall only be used, as applicable, by Respondent to respond to the RFP or by the Public Service to evaluate the response. Public Service and Respondent agree that they shall not disclose Confidential Information to agents or consultants unless the agent or consultant in question: 1) has a need to know such information; 2) agrees to only use the Confidential Information to respond to the RFP or evaluate the Response; and 3) is contractually bound to disclosure standards and policies at least as restrictive as those set forth in this paragraph. Regardless of the confidentiality, all such Confidential Information may be subject to: 1) state and federal freedom of information and open records act laws; 2) review by the appropriate state jurisdiction; 3) any other governmental authority or judicial body with jurisdiction relating to these matters; and 4) legal and regulatory discovery. Under such circumstances, Public Service or Respondent, as applicable, shall notify the other party regarding such circumstances to allow it to seek a protective order, as appropriate, or otherwise prevent the disclosure of the Confidential Information, as legally permitted. Public Service and Respondent shall make all reasonable efforts to preserve the

confidentiality of the Confidential Information, but acknowledge that such treatment is neither automatic nor guaranteed. Public Service and Respondent also specifically anticipate that proposals, including portions containing Confidential Information, will likely be filed with the Colorado Public Utilities Commission and agree to such disclosure provided the filing party seeks an appropriate protective order. Public Service and Respondent both recognize and acknowledge that the Independent Evaluator will have access to Confidential Information.

7.0 Addenda to RFP

Any additional responses required from Respondents as a result of an Addendum to this RFP shall become part of each proposal.

8.0 Evaluation Process and Criteria

The objective of Public Service's RFP proposal evaluation is to identify proposals that can reliably and cost-effectively meet the needs identified in Attachment A so as to allow Public Service to defer or avoid the Major Distribution Grid Project(s) in question. The proposed services will be evaluated as will Respondent's ability to provide those services. Public Service will also consider pricing and any proposed revisions to the terms of the model contract attached hereto as Attachment B and Respondent's proposed timeline and schedule.

8.1 Evaluation Process

Public Service's evaluation team will evaluate proposals; however, Public Service reserves the right to retain the services of outside experts to assist in its evaluation of proposals. In addition, the Independent Evaluator shall also conduct a review. The RFP Coordinator may contact Respondents directly, at any point during the evaluation process, for the purposes of clarifying proposals.

Proposals will be evaluated using a multi-step process as follows:

Step 1 – Proposal Eligibility Screening

Each proposal will be reviewed by the Evaluation Team to ensure it contains the required components set forth in this RFP.

Step 2 – Proposal Review by Public Service

Review and evaluation of proposals by Public Service, including assessment using a cost-benefit methodology pursuant to Rule 3535 of the Colorado Public Utilities Commission's Electric Rules (4 Code of Colorado Regulations 723-3). Selection of RFP Finalist(s) for further discussion and/or negotiation. Contemporaneous review by the Independent Evaluator

Step 3 – Finalist(s) and Selection for Negotiations

RFP Coordinator will notify any finalist(s) of selection for further discussion and/or negotiations. The Independent Evaluator will also file a report with the Commission within 30

days of Public Service's selection of a finalist.

8.2 Evaluation Criteria

Public Service will evaluate the responses to this RFP taking into account the specific information provided in the response and also incorporating, in its sole and unilateral discretion, any other implementation timing, legal, political, regulatory, economic or non-commercial considerations it deems relevant to its interests.

The response evaluation will include review of the quality and completeness of the proposal, including Respondent's prior experience providing services offered or services of a similar kind or nature. Central to Public Service's evaluation will be whether Respondent understands Public Service's requirements and can reliably and cost-effectively provide the Non-Wires Alternatives services so as to allow Public Service to defer or avoid the relevant Major Distribution Grid Project(s). Public Service will also consider pricing and any proposed revisions to the terms of the model contract attached hereto as Attachment B as well as Respondent's proposed timeline and schedule.

9.0 Response Timing and Information

Public Service has established the following general dates and processes for consideration of proposals received from this RFP:

- [insert date]: RFP Issued;
- [insert date]: Notice of Intent to Respond Due Date;
- Weeks of [insert] through [insert], Respondents may schedule conference calls with Public Service to discuss the RFP;
- [insert date]: Response Due Date;
- Weeks of [insert] through [insert]: Public Service will review responses and may reach out to Respondents for questions; and
- [insert date]: Notification to Respondents of Public Service decision.

Public Appendix 5 - Encoord Pilot Proposal

PSCO DISTRIBUTION SYSTEM PLAN PILOT PROPOSAL

1. Contact Information

1.1. Organization/Company Name:	encoord Inc. – Denver, Colorado
1.2. Full Name:	Rick Wallace Kenyon
1.3. Job Title:	Director of Product
1.4. Email:	wallace@encoord.com
1.5. Phone Number:	802-579-5172
1.6. Names of Partner Organizations (if applicable):	n/a

2. Overall Concept and Benefits (30%)

2.1. Pilot Proposal Title:

Targeted Least-Cost Electrification Planning via Integrated Gas and Electric System Simulations Emphasizing Non-Wires Alternatives and Disproportionately Impacted Community Benefits

2.2. [Concept] Describe the pilot concept.

Xcel Energy plans to reduce greenhouse gas emissions from its natural gas service by 25% by 2030. This will require a substantial electrification of natural gas heating demand, resulting in large load increases on the electric distribution system. Targeted electrification efforts can achieve this goal while minimizing the total cost by selecting under-utilized electric feeders that require minimal reinforcement, or aged gas sub-networks due for upgrades. Xcel Energy's clean energy transition goals can be supported by targeting territories amenable to non-wires alternatives (NWAs). Increased electric demands from electrification in regions of disproportionately impacted communities, which often consist of buildings with lower thermal performances, might be reduced with thermal efficiency upgrades. Identifying these complexly overlapping regions requires a robust and technical modeling approach including gas and electric system co-simulation, distributed energy resource dispatch optimization, and integration with the Low-Income Energy Affordability Data tool. This pilot project will develop, validate, and deliver a repeatable workflow that addresses these planning constraints.

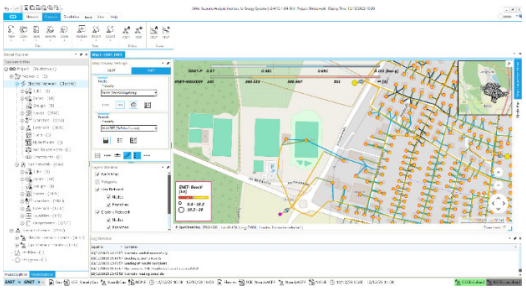


Figure 1: A screenshot of the SAInt software graphical user interface, with simulated electric and gas networks.

encoord executes electrification studies with SAInt, the Scenario Analysis Interface for energy systems analysis (Fig. 1). With a bedrock mapping feature, SAInt models electric distribution systems with unbalanced power flow, gas networks with hydraulic simulations, and generation dispatch with production cost modeling. Using electric and gas network and consumption data, encoord will execute an integrated electrification analysis to identify the duration and intensity of

electric system overloads. Long-duration, high-overloads require system upgrades, while shorter durations are candidates for NWAs and minor overloads may be mitigated with building efficiency upgrades. Employing the scenario analysis capabilities of SAInt to select and verify these mitigation approaches, territories can be selected for electrification based on the criteria of reducing system costs, NWAs, and benefits to disproportionately impacted communities.

2.3. [Goals] Describe which and how the pilot concept addresses the pilot goals.

Minimize distribution system costs – the electrification of gas customers is required for Xcel to meet its goal of a 25% reduction in greenhouse gas emissions by 2030. A targeted transition can reduce the costs associated with electrification by selecting overlapping territories with electric networks that do not need reinforcement to deliver the increased demand, and/or gas networks that already require upgrades due poor performance or age.

Reduce greenhouse gas emissions – the electrification of gas customers is an industry-accepted pathway to reduce greenhouse gas emissions. The core task of this pilot project is developing a robust and repeatable workflow for planning these electrification efforts.

Integrate Non-wires Alternatives – the electrification of gas customers has the potential to overload electric distribution systems. In some cases, when the overload is marginal and the duration is only a few hours a day, NWAs such as electric storage are a viable option for mitigating these overloads. This pilot project will identify NWA candidates and assess the viability of the solution using SAInt's production cost modeling capabilities and weather data integration.

Provide benefits to disproportionately impacted communities – this project will integrate the LEAD tool to identify regions of disproportionately impacted communities that may benefit from thermal efficiency housing upgrades. These upgrades can minimize electric distribution system upgrades necessary after electrification by reducing the increase in demand.

2.4. [Goals] Does the proposal prioritize benefits to disproportionately impacted communities? How?

The electrification of gas customers increases the electric demand on the electric distribution systems for obvious reasons. A less obvious solution to reduce this electric demand is to improve the thermal efficiency of the buildings being electrified. An upgraded building with improved thermal efficiency requires less electric energy to maintain livable temperatures than its non-upgraded counterpart. Often, the buildings with lower thermal efficiencies are those inhabited by members of disproportionately impacted communities. These inhabitants may not have the financial capacity to make these thermal efficiency upgrades with improvements to the building envelope insulation or retrofitting doors and windows. The LEAD tool was constructed to provide data about the housing and energy characteristics of low-income households. With this data and the simulation analysis capabilities of SAInt, these regions can be targeted for electrification, and housing efficiency upgrades to mitigate distribution system upgrade costs.

2.5. [Goals] Describe which and how the pilot concept addresses the Areas of Interest.

Increase utilization of distribution capacity due to high electrification – the electrification of gas customers will increase the demand on distribution systems. With a targeted electrification approach, portions of the distribution system that are under-utilized can be prioritized as leading

candidates. By targeting these regions for electrification first, the Xcel goal of a 25% reduction in greenhouse gas emissions by 2030 can be achieved with minimal system upgrade costs by increasing the utilization of under-utilized distribution systems.

2.6. [Metrics & KPIs] Describe how impacts and benefits of this pilot can be measured.

The workflow employed and further refined in this pilot project will require tuning of the following technical metrics that will be critical for identifying electrification territory candidates:

- Positive identification of candidate regions for electrification with electric and gas network co-simulation highlighting existing system deficiencies and upgrade cost savings.
- Refined capacity overload metrics that will indicate the best mitigation approach:
    - Cat-A: Substantial capacity violations for extended periods of time. Addressed primarily with system upgrades.
    - Cat-B: Unsubstantial capacity violations for shorter periods (a few hours a day) of time. Candidates for NWAs, due to shorter durations.
    - Cat-C: Unsubstantial capacity violations for extended periods of time. Candidates for efficiency upgrades, due to unsubstantial capacity violations.
- Confidence factors for the translation of gas demands to the corresponding electric network; disjoint overlay of infrastructure topologies presents uncertainty in this process, especially if a one-to-one mapping of gas and electric customers does not exist.

For each of the three phases of the pilot project (defined in section 3 below), one quantitative key performance indicator (KPI) will be agreed on between Xcel Energy and encoord at the start of the project. At the end of each phase, the result for the KPI will be defined by Xcel Energy as a metric for the success of the pilot project. Example KPIs for the three phases:

- **Data phase:** Percentage of the electric and gas infrastructure models that have been correctly imported and validated in SAInt for the pilot project territory.
- **Execution phase:** Percentage of the portions of the pilot project territory for which the impacts of one electrification scenario have been evaluated.
- **Reporting phase:** Percentage of the portions of the pilot project territory for which the cost of electrification has been calculated in a consistent and robust manner.

3. Project Implementation (35%)

3.1. [Schedule and Timeline] Estimate the general timeline of the pilot, including any factors that could impact this timeline (e.g., customer engagement, engineering, procurement and construction).

The proposed pilot project has a six-month duration. encoord conceptually divides these types of electrification studies into three broad phases: data, execution, and reporting. The expected size of the territory to be studied is in the 100,000 gas/electric customer range.

Data phase (2-month duration): includes the acquisition, grooming, importing, and data validation process. encoord has a verified and robust data integration process that concludes with statistical and targeted validation of the simulation of electric and gas networks in SAInt (see Fig. 2). This phase of the project also includes the definition of demand profiles for electric and gas customers, as well as the translation of weather data to variable renewable energy

generation profiles. This time-series data is required for the overload assessment. The final step is the integration of the LEAD tool data via geographic shape files into the SAInt ecosystem.

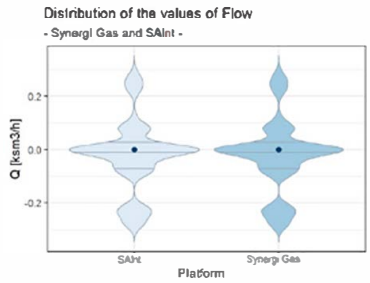


Figure 2: A violin statistical plot of flow data across a physical gas network, established in Synergi Gas and imported/validated in SAInt.

Execution phase (3-month duration): under-utilized portions of the electric distribution system and poorly performing regions of the gas system are identified with rigorous simulation. Gas demands are converted to electric demands and distribution system overloads are identified with static and sequential time-series simulations. Mitigation schemes, such as system reinforcement, NWAs, or demand reductions based on housing stock efficiency upgrades, are validated with simulation and optimization studies.

Reporting phase (1-month duration): the results and associated costs of the execution phase are packaged for consumption by planners and policymakers to assist in targeted electrification decisions. The simulation workflow is thoroughly documented and packaged for use by Xcel's integrated planning team for a repeatable application across all relevant territories.

3.2. [Costs] Provide a budget estimate to carry out the pilot and describe your request of Xcel Energy and its role/responsibilities. If possible, share cost categories.

Budget: [redacted]

Personnel:

Role	Hourly Rate	Hours
Principal Energy Planner	[redacted]	400
Energy Systems Modeler(s)		1,200

Cost share: SAInt software license fees and software training for Xcel Energy engineers and planners will be provided at no cost to Xcel Energy in the form of in-kind cost share by encoord.

encoord will require data and limited participation from engineers and planners, including:

- Electric distribution system data, with latitude and longitude components.
- Gas distribution system data, with latitude and longitude components.
- Electric and gas consumption profiles, either AMI or substation/source flows.
- Discussion with planners on standard Xcel upgrade protocols and equipment pricing.

3.3. [Risks] Describe the most critical factors and risks for successful implementation of the pilot. Describe corresponding mitigation strategies.

The quality of the data used is one of the most critical factors in highly technical and targeted planning studies like this pilot project. The gold-standard is thoroughly vetted electric distribution system and gas system models down to the customer meter level, with AMI consumption data for all demands on both networks. Realistically, most electric distribution system models terminate at service transformers, and gas models have flow demands represented by an aggregate of customers. encoord has developed demand mapping methods that use a variety of network and proximity analyses metrics to bestow confidence on the accuracy of gas demand re-allocation to the correct electric feeder and phase. These methods provide a study template for large network analyses. Using them, questionable conversions can be flagged and further investigated by the planning engineer executing the study.

4. Viability (35%)

4.1. [Experience] Has the proposed technology, concept or solution been implemented before? What is the Technology Readiness Level of the proposed concept, platform or hardware? Why is conducting a PSCo distribution pilot the next step?

encoord has developed the software SAInt, which is a commercially available, scenario analysis tool for energy system modeling (see Fig. 1) that is in use by customers across the world. Our customers include National Grid US, who employ the software for electrification studies similar to the core electrification analysis of this pilot project. Their studies are based on a workflow that encoord developed with the SAInt software for analysis of portions of the New York National Grid integrated gas and electric territories. Conducting a PSCo distribution pilot with the integration of the LEAD tool is a clear next step to exercise these core workflow methodologies while incorporating benefits to disproportionately impacted communities.

4.2. [Scalability] Describe how the pilot can be scaled to a long-term and operational solution. Describe how the concept proposal aligns with the continued development of the PSCo distribution system.

A primary objective of this pilot project is the construction and implementation of a workflow based on a subset of PSCo territories and data, along with the metrics as indicators of reasonable overload mitigation schemes. This workflow will then be delivered as a blueprint for executing electrification studies across PSCo territories, to bolster a targeted and least cost approach to planning and developing distribution systems while considering the greenhouse gas emissions reductions, increased use of NWAs, and a prioritization of benefits for disproportionately impacted communities.

4.3. [Personnel] What is your organization's (and partner organizations') experience in implementing the pilot concept? What additional knowledge or resources are needed to implement a successful pilot?

encoord personnel have substantial experience working with utilities in the Northeastern United States on targeted electrification studies similar to this pilot project within the scope of integrated gas and electric networks and electrification agendas. Resources that will be needed to make this a successful pilot project will be some level of consistent interaction with planners and engineers from Xcel Energy (a minimum of one meeting per week during the project), who can provide answers to questions specific to the territory under study as they arise.

Appendix 6 - ICF Climate Risk & Resiliency Study

PUBLIC SERVICE COMPANY OF COLORADO CLIMATE RISK AND RESILIENCY STUDY

OCTOBER 31, 2024

Submitted by:
ICF Resources, LLC
1902 Reston Meto Plaza
Reston, VA 20190

CONTENTS

Figures **4**

Tables **5**

Abbreviations **7**

Executive Summary **8**

Introduction **11**

Purpose 11

Study approach 12

Exposure and sensitivity 13

Vulnerability and Resilience Framework 15

Climate Science: Data, Methods, and Results **17**

Overview 17

Climate Datasets and Pathways 18

Historical Climate Data, Future Climate Projections, And Asset exposure 19

Extreme Heat 21

Frozen Precipitation 27

Extreme Wind 30

Riverine Flooding 35

Wildfire 39

Extreme Events: cold snaps and polar vortex events 42

Vulnerability Assessment **43**

Sensitivity 43

Criticality 44

Potential Impact 46

Individual-asset Vulnerability 48

Results 51

Operations and processes vulnerability 55

Risk scoring **60**

Baseline Outage Estimate 61
Number of critical facilities 62
Customers in Disadvantaged Communities 62
Project prioritization and adaptation 65
Potential Resilience Measures 67
Resilience Framework 67
Resilience Measures 68
Conclusion and Next Steps 73
Appendices 76
Appendix I – Climate Science Variables and Methods 76
Appendix II – Asset exposure scores 77
Appendix III – Asset sensitivity 82
Appendix IV – Vulnerability scores 84
Appendix V – Operational vulnerability 88
Appendix VI – Risk scores tables 96
References 100

WARRANTIES AND REPRESENTATION

ICF endeavors to provide information and projections consistent with standard practices in a professional manner. This climate vulnerability assessment has been prepared for Xcel Energy (Public Service Company of Colorado). The information contained in this document is based on data and assumptions available at the time of preparation. While every effort has been made to ensure the accuracy and reliability of the information provided, ICF and its affiliates make no warranties expressed or implied (including without limitation any warranties of merchantability or fitness for a particular purpose), as to this report.

FIGURES

Figure 1. Diagram illustrating maximum asset vulnerability to different climate hazards by 2050 under SSP2-4.5 50th percentile projections. 9
Figure 2. Risk scoring process. 10
Figure 3. PSCo's service territory. 11
Figure 4. Climate vulnerability assessment timeline. 11
Figure 5. Diagram illustrating the vulnerability assessment approach. 12
Figure 6. Resilience framework. 17
Figure 7. Projected global surface temperatures under three different SSP scenarios. 19
Figure 8. Exposure scoring symbology. 20
Figure 9. Maximum asset exposure by 2050 (SSP2-4.5 50th percentile) for each climate hazard. 20
Figure 10. Historically observed and future projections of 30-year daily maximum temperatures across the PSCo service territory. 21
Figure 11. Historically observed and future projections of the number of days per year with daily maximum temperature over 95˚F across the PSCo service territory. 22
Figure 12. Historically observed and future projections of the number of days per year with daily maximum temperature over 104˚F across the PSCo service territory. 22
Figure 13. Observed and projected frequency of 2-day or greater heat waves across the PSCo service territory. 23
Figure 14. Observed and projected duration of 2-day or greater heat waves across the PSCo service territory. 23
Figure 15. Maximum heat exposure scores by county by 2050 (SSP2-4.5 50th percentile). 25
Figure 16. Projected percent of Solar Panel, Overhead Conductor, and Substation Transformer assets exposed to extreme heat in 2030, 2050, and 2080 under the SSP2-4.5 50th percentile scenario. 26
Figure 17. Projected percent change in the maximum 1-day frozen precipitation amounts by 2050 across the PSCo service territory. 27
Figure 18. Maximum frozen precipitation exposure scores (SSP2-4.5 50th percentile) by county by 2050. 28
Figure 19. Projected percent of Solar Panel, Overhead Conductor, and Substation Transformer assets exposed to ice in 2030, 2050, and 2080 under the SSP2-4.5 50th percentile scenario. 29
Figure 20. FEMA's National Risk Index (NRI) Strong Wind Risk Categorization for counties across Colorado. 30
Figure 21. Observed maximum wind gust speed is shown on the left. The projected change in the number of annual days with average wind speeds above the 90th percentile historical average wind speeds by 2050 across the PSCo service territory is shown on the right. 31
Figure 22. Maximum wind exposure scores (SSP2-4.5 50th percentile) by county by 2050. 33
Figure 23. Projected percent of Solar Panel, Overhead Conductor, and Substation Transformer assets exposed to wind gusts by 2030, 2050, and 2080 under the SSP2-4.5 50th percentile scenario. 34
Figure 24. Present-day 100- and 500-year FEMA floodplain extent with respective 1% and 0.2% annual flood probabilities across Colorado, where available. 35
Figure 25. Projected percent change in the maximum 5-day precipitation by 2050 across the PSCo service territory. 36
Figure 26. Pad mount transformers in the FEMA 100- and 500-year floodplains. 37
Figure 27. Projected percent of Solar Panel, Overhead Conductor, and Substation Transformer assets exposed to riverine flooding in 2030, 2050, and 2080 under the SSP2-4.5 50th percentile scenario. 38

Figure 28. Historical relative wildfire likelihood across Colorado, from the USFS Wildfire Risk to Communities Dataset. 39
Figure 29. Projected change in the number of summer days above historical 95th percentile FWI by 2050 across the PSCo service territory. 40
Figure 30. Maximum wildfire exposure scores (SSP2-4.5 50th percentile) by county by 2050. 41
Figure 31. Projected percent of Solar Panel, Overhead Conductor, and Substation Transformer assets exposed to wildfire in 2030, 2050, and 2080 under the SSP2-4.5 50th percentile scenario. 42
Figure 32. Vulnerability assessment approach. 43
Figure 33. Guide for plot interpretation. 51
Figure 34. Vulnerability scores distribution for overhead conductors and substation transformers to extreme heat. 52
Figure 35. Vulnerability scores distribution for overhead conductors and substation transformers to frozen precipitation. 53
Figure 36. Vulnerability scores distribution for solar panels to wind. 53
Figure 37. Vulnerability scores distribution for substation transformers and solar panels to riverine flooding. 54
Figure 38. Vulnerability scores distribution for overhead conductors and solar panels to wildfire. 55
Figure 39. Risk scoring process diagram 60
Figure 40. Consequence scoring metrics. 61
Figure 41. Disadvantaged communities in PSCo's service territory 63
Figure 42 - Dimensions of the resilience framework. 68

TABLES

Table 1. List of assets included in the Study. 13
Table 2. Priority vulnerabilities. 15
Table 3. Extreme heat exposure scoring rubric. 24
Table 4. Frozen precipitation exposure scoring rubric. 28
Table 5. Extreme Wind exposure score rubric. 32
Table 6. Riverine flooding exposure score rubric. 37
Table 7. Wildfire exposure scoring rubric. 40
Table 8. Criticality scores for each asset. 45
Table 9 . Potential Impact scoring rubric 46
Table 10. Potential Impact scores of asset–hazard combinations. 47
Table 11. List of priority vulnerabilities. 47
Table 12. Vulnerability scoring rubric. 48
Table 13. Counties with assets with medium or high vulnerability to climate hazards. 50
Table 14. Summary of operations and processes vulnerable to climate change. 56
Table 15. Example consequence scores for transformers assets and exposure to extreme heat. 63
Table 16. Heat and Flood risk scores for substation transformers. 64
Table 17. Heat and Flood risk scores of substations transformers identified for replacement due to condition. 65
Table 18. Heat and Flood risk scores of substations associated with capacity upgrade projects. 66

Table 19. Resilience measures to enhance resilience to wind and frozen precipitation. 69
Table 20. Resilience measures to enhance resilience to riverine flooding. 70
Table 21. Adaptation measures to enhance resilience to extreme heat. 71
Table 22. Adaptation measures to enhance resilience to wildfires. 72
Table 23. Climate hazards and their associated variables. 76
Table 24. Asset exposure score distribution across PSCo service territory for extreme heat. 77
Table 25. Asset exposure score distribution across PSCo service territory for frozen precipitation. 78
Table 26. Asset exposure score distribution across PSCo service territory for extreme wind. 79
Table 27. Asset exposure score distribution across PSCo service territory for riverine flooding. 80
Table 28. Asset exposure score distribution across PSCo service territory for wildfire. 81
Table 29. Asset sensitivity to extreme heat. 82
Table 35. Asset vulnerability score distribution across PSCo service territory for extreme heat. 84
Table 36. Asset vulnerability score distribution across PSCo service territory for ice. 84
Table 37. Asset vulnerability score distribution across PSCo service territory for extreme wind. 85
Table 38. Asset vulnerability score distribution across PSCo service territory for riverine flooding. 86
Table 39. Asset vulnerability score distribution across PSCo service territory for wildfire. 87
Table 40. Asset risk score distribution across PSCo service territory for extreme heat. 96
Table 41. Asset risk score distribution across PSCo service territory for ice. 96
Table 42. Asset risk score distribution across PSCo service territory for extreme wind. 97
Table 43. Asset risk score distribution across PSCo service territory for riverine flooding. 98
Table 44. Asset risk score distribution across PSCo service territory for wildfire. 99

ABBREVIATIONS

AMI	Advanced Metering Infrastructure
BESS	Battery Energy Storage System
CMIP6	Coupled Model Intercomparison Project Phase 6
CSP	Completely Self Protected
DAC	Disadvantaged Community
DER	Distributed Energy Resource
FWI	Fire Weather Index
GCM	Global Climate Model
GHG	Greenhouse Gas
HVAC	Heating, ventilation, and air conditioning
IPCC	Intergovernmental Panel on Climate Change
LOCA2	Localized Constructed Analogs Version 2
NCA	National Climate Assessment
NEX-GDDP	NASA Earth Exchange Global Daily Downscaled Climate Projections
NRI	National Risk Index
PSCo	Public Service Company of Colorado
PUC	Public Utilities Commission
PV	Photovoltaic
SCADA	Supervisory Control and Data Acquisition
SME	Subject Matter Expert
SSP	Shared Socioeconomic Pathway

EXECUTIVE SUMMARY

Public Service Company of Colorado ("PSCo" or "the Company"), a subsidiary of Xcel Energy, operates in multiple regions across the state of Colorado to deliver electricity to approximately 1.5 million customers. Global climate has been changing and is continuing to change rapidly due to both natural forces and human-caused greenhouse gas emissions (GHG) emissions, and these changes manifest at regional and local levels. In Colorado, PSCo is already experiencing extreme heat, flooding, and wildfires, among other climate events. In the coming decades, such events are projected to multiply and intensify.

With a commitment to delivering energy safely and reliably to customers, leading the clean energy transition, prioritizing customers in Company decisions, and keeping customer costs low, PSCo is taking action to address climate risks across its operations and assets. This involves understanding climate projections, assessing vulnerability across the Company, and tailoring resilience measures to address specific vulnerabilities. This Climate Risk and Resilience Study ("the Study") complies with the Colorado Public Utilities Commission (PUC) requirement for a "Climate Risk and Resiliency" section under the settlement agreement for proceeding no. 22A-0189E.

This Study assesses climate vulnerability of the Company's distribution, substation, and distributed energy resources (DERs) assets across five different climate hazards: (1) extreme heat, (2) frozen precipitation, (3) wind, (4) riverine flooding, and (5) wildfire. The analysis was led by ICF (a third-party consultant), and PSCo subject matter experts (SMEs) provided asset data, detailed input and feedback through ongoing discussions, interviews, workshops, and progress reviews. To do so, both asset and operations vulnerability were analyzed for each of the climate hazards listed above. Figure 1 provides an overview of vulnerability results across all assets in the service territory to different hazards by 2050, under SSP2-4.5, 50th percentile. Vulnerability to frozen precipitation is projected to be lower than wind, riverine flooding, and wildfire. Assets are projected to have higher vulnerability to extreme heat.

This Study does not dictate a specific set of investments. Instead, it provides a framework to integrate climate hazards into capital planning by identifying vulnerabilities and informing the justification of business-as-usual projects that may also enhance resilience.

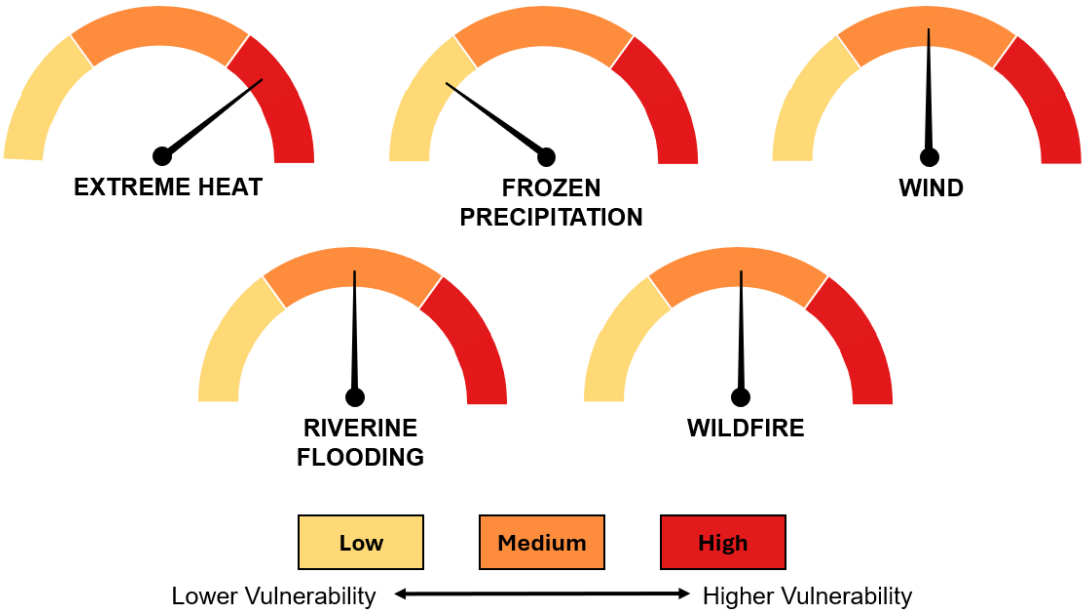


Figure 1. Diagram illustrating maximum asset vulnerability to different climate hazards by 2050 under SSP2-4.5 50th percentile projections.

The Study Team (i.e., ICF and PSCo SMEs) evaluated the climate impacts on 10 distinct utility operations and processes. These included 1) load forecasting, 2) load relief planning, 3) portfolio planning and prioritization, 4) asset ratings, 5) flood design, 6) reliability assessment and planning, 7) work practices and safety, 8) emergency preparedness, 9) vegetation management, and 10) asset management. The team found that inclusion of extreme heat projections, as opposed to historical data, into these processes would result in more resilient operations. The Study found specific areas where wildfire and inland flooding conditions might become worse. Future updates to operations (e.g., emergency preparedness and vegetation management) can be informed by the projections to these hazards.

The second goal of the Study was to help investment decisions become climate informed. To achieve this, risk scores were calculated at the individual-asset level by combining vulnerability and consequence. Consequence captures the significance of an asset for customers. Three metrics of consequence were evaluated for each asset: (1) number of critical facilities associated with the asset, (2) disadvantaged communities served by the asset, and (3) outage estimate caused by asset failure. Critical facilities encompass facilities the community relies on, such as hospitals, public utilities, and safety facilities. The Study Team identified assets that serve disadvantaged communities[1] and established outage estimates based on the vulnerability of each asset to a specific

[1] A disadvantaged community is defined as low-income communities, communities of color, housing cost-burdened communities, linguistically isolated communities, historically marginalized communities, cumulatively impacted communities, tribal lands, and/or mobile home communities. Colorado's EnviroScreen website, the source for geographic DAC data, can be found here: https://cdphe.colorado.gov/enviroscreen.

hazard. The risk scoring process is depicted in Figure 2. In the future, risk scores can be incorporated into decision-making criteria to invest in climate-informed capital projects.

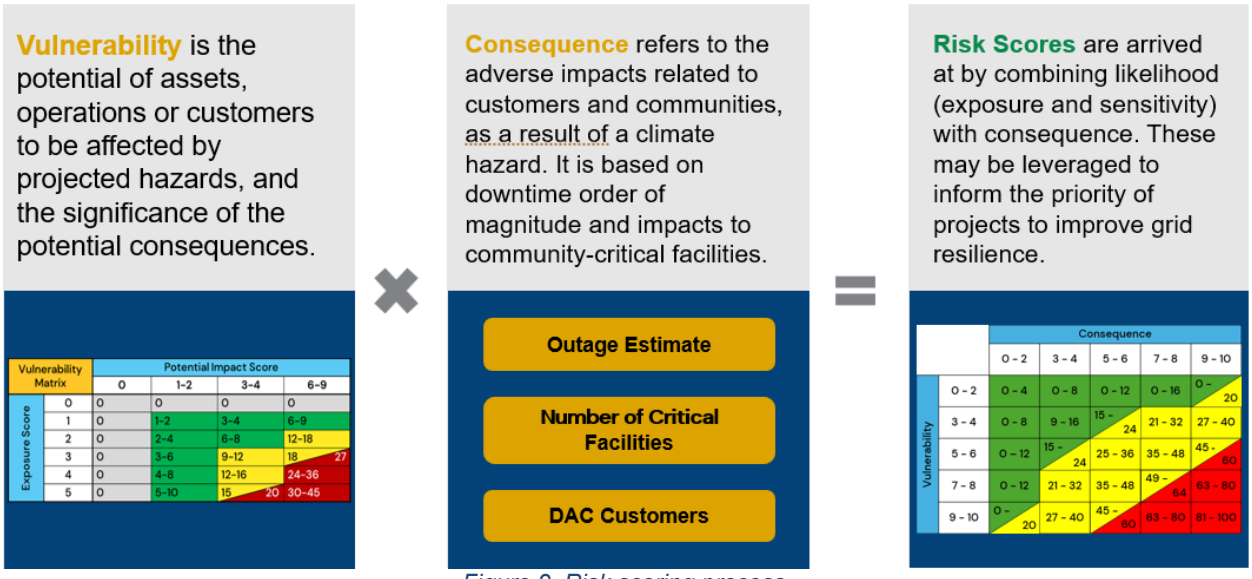


Figure 2. Risk scoring process.

Climate resilience is not a new concept for PSCo, and the Company has already started work toward becoming a more resilient electric utility. For example, in 2019 PSCo updated their wildfire mitigation strategies and implemented new actions to mitigate wildfire risk, such as targeted undergrounding of lines in high wildfire risk areas and accelerated and expanded vegetation management.[1] PSCo has also built considerations of impacts from storms and extreme events into budgeting to prioritize safety and reliability of PSCo's system while staying within the annual capital budget.

Building on this previous and ongoing resilience work, this Study uses a multi-pronged resilience framework to identify specific resilience measures to address the identified operational and physical vulnerabilities. The multi-pronged resilience framework comprises four key objectives:

- Strengthen assets and operations to **withstand** the adverse impacts of a climate hazard event.
- Increase the system's ability to anticipate when a climate hazard event may occur and **absorb** its effects.
- Bolster the system's ability to quickly respond and **recover** in the aftermath of a climate hazard event.
- **Advance** and adapt the system to address a continuously changing threat landscape and perpetually improve resilience.

INTRODUCTION

PURPOSE

Colorado's climate is changing and is projected to continue shifting in the decades ahead. In recognition of the impact of climate change on safe and reliable energy delivery, the PUC directed PSCo to further its use of data related to climate risks that could be used to inform cost-effective distribution investment decisions.[2] The requirement was part of the settlement agreement for proceeding no. 22A-0189E in November 2022. This Climate Risk and Resiliency Study constitutes PSCo's fulfillment of this requirement.

PSCo established a "Study Team" comprised of internal subject matter experts (SMEs), distribution planning and engineering staff, and ICF as a third-party consultant. This Study presents the results of the Study Team's work, which includes climate hazard projections developed for the PSCo's service territory (Figure 3), identified vulnerabilities of distribution system assets to various climate hazards, risk scores for specific asset–hazard combinations to help inform distribution planning investment decisions, and identified potential climate resilience measures.

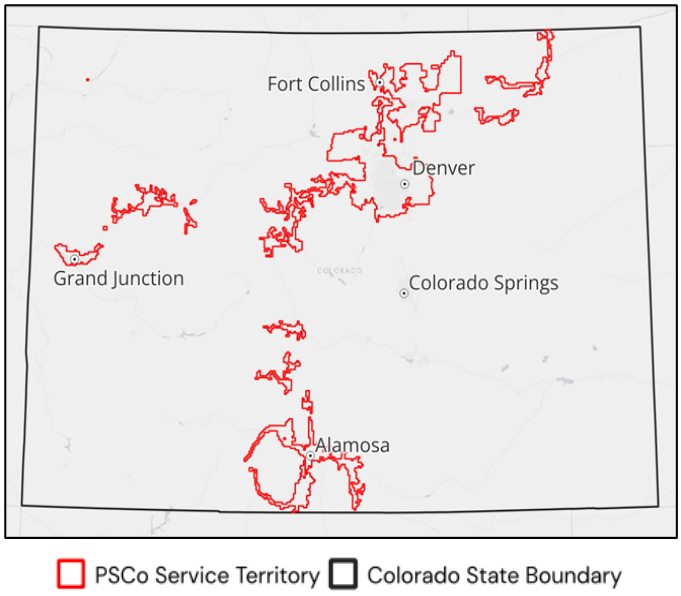


Figure 3. PSCo's service territory.

This report summarizes the one-year effort shown in the timeline below.

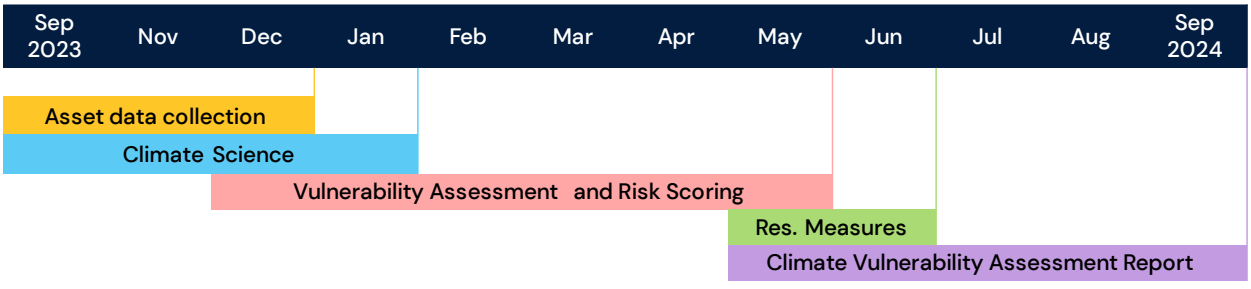


Figure 4. Climate vulnerability assessment timeline.

[2] This study focused only on distribution electric level assets.

STUDY APPROACH

The vulnerability assessment process applies climate science projections to PSCo's system to identify specific asset and operational vulnerabilities. Figure 5 depicts the approach used for assessing the vulnerability of PSCo's electric assets.

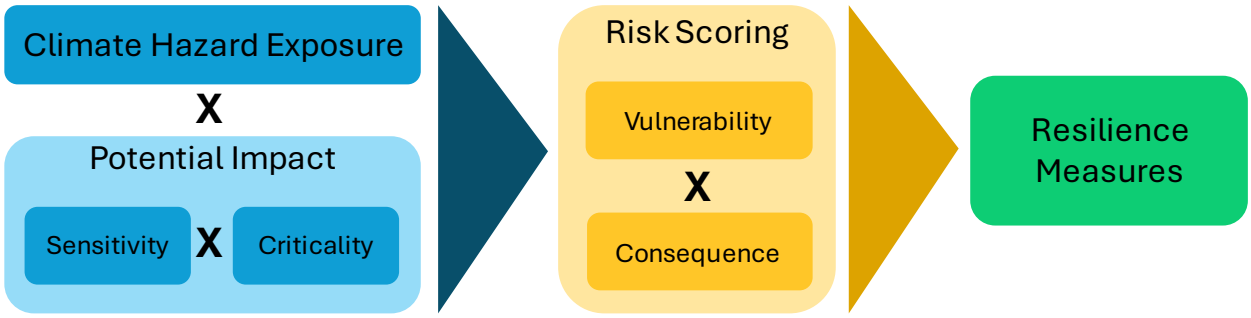


Figure 5. Diagram illustrating the vulnerability assessment approach.

The Study Team began by developing downscaled climate projections for priority hazards across the PSCo service territory, defining asset criticality, and asset–hazard combination sensitivity. This information was then combined with exposure results for specific assets to develop vulnerability scores for specific asset–hazard combinations. Finally, the vulnerability scores are combined with consequence metrics to arrive at individual-asset-level risk scores. All this information is intended to support PSCo in better understanding how climate change will impact their assets and operations and help the Company bolster resilience accordingly.

The following definitions are used for each of the components of the risk scoring process:

- **Exposure:** the degree to which assets could face climate hazards.
- **Sensitivity:** the degree to which assets could be negatively affected by exposure to a climate hazard.
- **Criticality:** the magnitude of negative outcomes for the electrical system in the event of asset failure or damage.
- **Vulnerability:** the potential for assets and operations to be adversely impacted by projected climate hazards.
- **Consequence**: the significance of the impact on an asset for customers and estimated duration.

The assets listed in Table 1 below were selected for this analysis because they represent common components and the typology of the electric distribution system and are the most critical for the system to function.

Table 1. List of assets included in the Study.

Distribution	Substations	Distributed Energy Resources
Distribution poles	Transformers/voltage regulators	Battery storage
Overhead conductors	Circuit breakers	Solar panels
Overhead transformers	Protection & control devices	-
Pad-mount transformers	Control room/control house	-

EXPOSURE AND SENSITIVITY

The Study Team leveraged the best available climate data to develop projections of five climate hazards across its service territory: 1) **extreme heat**, 2) **frozen precipitation**, 3) **wind**, 4) **riverine flooding**, and 5) **wildfire**. Based on consultations with the Study Team's SMEs, these hazards were selected for in-depth analysis. For each hazard, the assessment analyzed climate variables that are associated with physical design standards or operational thresholds of PSCo's assets.

Extreme Heat

Critical assets, such as substation transformers and overhead conductors, are sensitive to high heat. Both acute (e.g., heat waves) and chronic (e.g., long-term average summer temperature warming) heat pose challenges to PSCo's ability to deliver energy safely and reliably to customers. Heat can accelerate asset aging and degradation and lead to asset failure. Given that climate change is expected to increase ambient temperatures and lead to more frequent and severe extreme heat events, it is crucial for PSCo to understand and prepare for this significant climate hazard. This Study used maximum temperature projections, number of days with maximum temperature above 95°F and 104°F, and frequency and duration of heat waves to understand the potential exposure of PSCo's assets to extreme heat.

Overhead conductors, overhead transformers, pad-mount transformers, and substation transformers and regulators all have a moderate sensitivity to extreme heat. Additionally, operational processes, such as load forecasting, load relief planning, portfolio planning and prioritization, asset ratings, and reliability assessment and planning, can be impacted by changes in extreme heat.

Frozen Precipitation

Ice storms and winter storms can result in ice accumulation that threatens the integrity of assets and operations and service reliability, especially when ice is combined with high winds. For example, radial icing can significantly impact distribution line structures, leading to asset failure and outages as added weight on the line causes line sag, line failure, and other consequences. This Study evaluated annual maximum frozen

precipitation to understand the potential exposure of PSCo's assets to frozen precipitation in the future.

Assets differ in their sensitivity to frozen precipitation. For example, overhead conductors are highly sensitive to frozen precipitation, while distribution poles, overhead transformers, substation transformers and regulators, circuit breakers, and solar panels have a moderate sensitivity to frozen precipitation. Additionally, operational processes, such as portfolio planning and prioritization, reliability assessment and planning, work practices and safety, and emergency preparedness, response, and restoration, can be vulnerable to changes in frozen precipitation.

Extreme Wind

Extreme wind can significantly impact overhead distribution assets and solar panels. Strong winds can damage conductors and overhead structures or indirectly cause impairment via downed trees and limbs. Climate change is projected to drive increasingly extreme weather events that could increase associated wind gusts. This Study leveraged annual maximum 1-day average wind speed and historical wind gusts to evaluate the potential exposure of different PSCo assets to extreme wind.

In general, distribution poles, overhead conductors, and solar panels are the assets with the highest sensitivity to extreme wind. Additionally, operational processes, such as portfolio planning and prioritization, asset ratings, reliability assessment and planning, work practices and safety, emergency preparedness, response, and restoration, vegetation management, and asset management, are more vulnerable to changes in extreme wind.

Riverine Flooding

Flooding can pose a significant risk to utility assets installed at grade and within floodplains. Colorado has a complex network of river and drainage systems, resulting in an increased potential for riverine flooding throughout the state. Given that heavy precipitation is a primary driver of riverine flooding, this Study evaluated future changes in heavy precipitation combined with Federal Emergency Management Agency (FEMA) floodplain data to identify areas exposed to flooding across the PSCo service territory.

Assets with the highest sensitivity to riverine flooding include batter storage, control rooms/houses, and pad-mount transformers. Additionally, distribution poles, substation transformers and regulators, circuit breakers, protection and control devices, and solar panels have a moderate sensitivity to riverine flooding. Operational processes, including portfolio planning and prioritization, asset ratings, flood design, reliability assessment and planning, work practices and safety, emergency preparedness, response, and restoration, and asset management, are more vulnerable to changes in riverine flooding.

Wildfire

Wildfires can result in significant power outages for customers, with potentially lengthy and costly restoration of damaged assets and infrastructure. This Study leveraged historical burn probability data and the Canadian Fire Weather Index (FWI). FWI accounts

for daily temperature, relative humidity, wind speed, and precipitation to provide an understanding of how conducive the projected conditions are to wildfire development.

Not all assets are equally sensitive to wildfires. Distribution poles, pad-mount transformers, battery storage, and solar panels have the highest sensitivity to wildfire and wildfire damage. Overhead conductors, overhead transformers, and circuit breakers have a moderate sensitivity to wildfire. Additionally, operational processes, including portfolio planning and prioritization, work practices and safety, emergency preparedness, response, and restoration, vegetation management, and asset management, are all vulnerable to changes in wildfire.

VULNERABILITY AND RESILIENCE FRAMEWORK

After evaluating the overall level of exposure and sensitivity for each asset family to specific climate hazards, the Study Team analyzed vulnerability at an individual-asset level for the identified priority vulnerabilities. The selected priority vulnerabilities (i.e., asset–hazard combination of highest concern) are shown in Table 2. A check in the table indicates that the asset–hazard combination was analyzed at the individual-asset level.

Table 2. Priority vulnerabilities.

Asset Family	Extreme Heat	Frozen Precipitation	Extreme Wind	Riverine Flooding	Wildfire
Distribution					
Poles		✓	✓	✓	✓
Overhead Conductors	✓	✓	✓		✓
Overhead Transformers	✓				✓
Pad-mount Transformers	✓			✓	✓
Substations					
Substation transformers/regulators	✓	✓		✓	
Circuit breakers		✓		✓	
Protection & control devices				✓	
Control Room/ Control House				✓	
Distributed Energy Resources					
Battery Storage				✓	✓
Solar Panels		✓	✓	✓	✓

The vulnerability ratings for specific asset–hazard combinations presented in this Study are a valuable indicator of whether an asset might be impacted by a given climate hazard. Asset-specific characteristics were leveraged to understand the criticality of the outcome to PSCo's customers if a given asset is impacted (i.e., consequence).

The scoring of consequence was characterized for each asset based on three metrics: (1) outage estimate, (2) number of critical facilities, and (3) whether the asset served a

disadvantaged community. Outage estimate is an order-of-magnitude-type metric that characterizes the expected time that it would take to restore service after an asset was exposed to a specific hazard. The number of critical facilities[3] was added at the feeder level and represents the importance the assets associated to each feeder might have for community services. The last metric captures equity considerations by establishing whether or not the asset serves a disadvantaged community, as defined by the Colorado Department of Public Health and Environment[2].

The result of the combination of vulnerability and consequence is a risk score. It can be used to identify resilience-specific potential investments, to bolster the justification of previously identified capital investments, and to evaluate whether other previously identified projects will also yield resilience benefits as scoped or with marginal additions.

Drawing on these results, the Study Team identified potential resilience measures to address both physical and operational climate vulnerabilities. The adopted resilience framework (Figure 6) seeks to identify resilience measures that achieve at least one of the following goals:

1. **Strengthen** assets and operations to **withstand** the adverse impacts of a climate hazard event.
2. Increase the system's ability to **anticipate** when a climate hazard event may occur and **absorb** its effects.
3. Bolster the system's ability to quickly **respond** and **recover** in the aftermath of a climate hazard event.

[3] Critical facilities include facilities that support the health and safety of communities, such as hospitals, water treatment plants, and emergency response facilities. PSCo is currently updating the list of critical facilities used for this study; therefore, the results presented in this study are illustrative and will need to be updated.

4. **Advance** and **adapt** the system to address a continuously changing threat landscape and perpetually improve resilience.

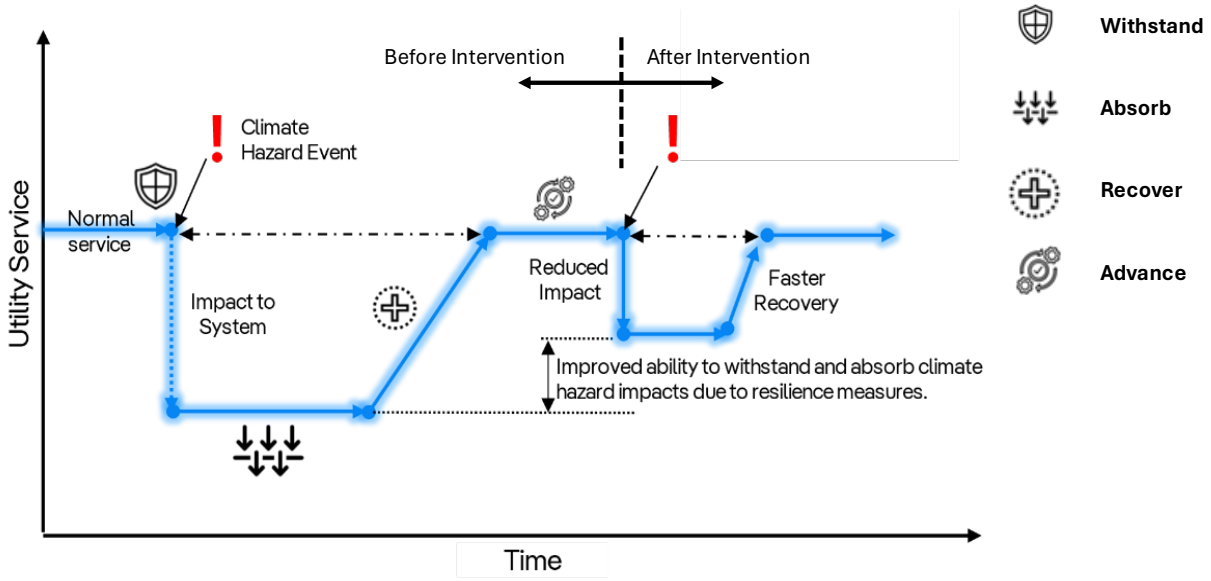


Figure 6. Resilience framework.

CLIMATE SCIENCE: DATA, METHODS, AND RESULTS

OVERVIEW

Climate change refers to long-term shifts in temperature or weather patterns. Such shifts can occur due to both natural and human-caused forces. Climate change drives shifts in both chronic and acute weather conditions. Increasing average temperatures and sea level rise are examples of chronic weather conditions. Extreme storms, heat waves, or heavy rainfall are examples of acute weather conditions that may change in frequency and intensity.

The Study Team evaluated both historical and future climate data to understand how climate change has already and will continue to affect its service territory. Forward-looking climate hazard projections provide the basis for evaluating climate hazard exposure and calculating vulnerability as part of this Study. It is important to note that these climate projections are not precise predictions for weather due to an incomplete understanding of Earth's system, natural climate variability, model limitations, observational errors, and other factors. Rather, they provide predictive data that can help PSCo assess and prepare for a range of potential future climate outcomes. Projections suggest that climate change could drive shifts in temperature, precipitation, and wind patterns, as well as exacerbate a range of extreme weather events such as heat waves and flooding.

This section discusses the climate datasets used in this Study, explores the trends in current and future climate across the service territory, and introduces the climate

pathways selected by PSCo to standardize climate information and guide the Company's resilience planning. The Study also provides a detailed discussion of the assessment conducted to understand the potential exposure of PSCo's electric infrastructure to projected climate hazards.

CLIMATE DATASETS AND PATHWAYS

While there is inherent uncertainty in future climate, advanced tools provide insight into future climate conditions. Global climate models (GCMs) simulate future climate conditions based on assumed future GHG emissions trajectories. For this Study, the Study Team leveraged different climate projection datasets to evaluate future changes in priority climate hazards across its service territory and exposure of assets. The report draws primarily on Localized Constructed Analogs Version 2 (LOCA2)[3] and NASA Earth Exchange Global Daily Downscaled Climate Projections (NEX-GDDP)[4] downscaled Coupled Model Intercomparison Project Phase 6 (CMIP6) projection datasets, offering high-resolution grids of climate projections across the service territory. The datasets used in this Study are summarized in Appendix I.

Different emissions scenarios reflect different future trajectories of GHG emissions based on divergent global socioeconomic conditions. These scenarios are represented by the shared socioeconomic pathways (SSPs) developed in preparation for the Intergovernmental Panel on Climate Change's (IPCC) Sixth Assessment Report.[5] Climate projections developed from GCMs provide a mechanism for quantifying future changes under different scenarios and thus constitute useful tools for analyzing the potential impacts of climate change across a range of geographic scales. However, it is important to note the uncertainty inherent in climate projections and the fact that they only resolve longer-term climate trends and cannot capture day-to-day weather.

Due to uncertainty associated with future GHG emissions trajectories and the sensitivity of Earth's climate to these emissions, climate change projections provide a range of plausible climate futures. Specific climate pathways are often chosen to narrow this range and provide standardized climate projections. Ultimately, climate pathways represent the level of risk aversion the Company is comfortable with when planning for future climate change. The Study Team chose SSP2-4.5 50th percentile and SSP5-8.5 90th percentile climate scenarios for this analysis. SSP2-4.5 assumes significant GHG emissions mitigations prior to midcentury and represents a more risk-tolerant scenario while SSP5-8.5 represents high future emissions levels. Given current policies and emissions pledges, SSP2-4.5 is a more likely scenario than SSP5-8.5; however, it is important to note that future climate is uncertain as it hinges on interactions between a variety of different factors including total carbon emissions, earth system sensitivity, and climate policies.

PSCo's selection of the SSP2-4.5 50th percentile and SSP5-8.5 90th percentile pathways reflects careful consideration of different criteria, including peer benchmarking, analysis of the most up-to-date climate science, assessment of current climate policies, and

considerations of risk aversion and tolerance levels to plan for and adapt to climate change while also providing co-benefits like blue-sky functionality and resilient service to customers. The range of percentiles for each emissions scenario also provides a more complete array of potential climate futures for planning considerations. Projections were developed for the years 2030, 2050, and 2080 to support planning over the next few decades and will enable PSCo to proactively prepare for future climate change. Figure 7 illustrates global surface temperature change under different SSP scenarios through 2100, orange shading is used to indicate the range between SSP2-4.5 and SSP5-8.5 temperature projections used in the Study.

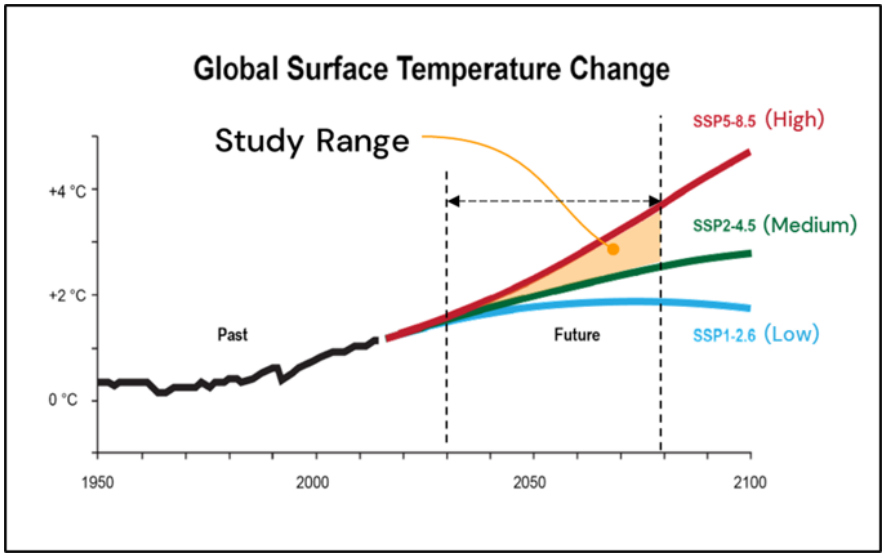


Figure 7. Projected global surface temperatures under three different SSP scenarios.

HISTORICAL CLIMATE DATA, FUTURE CLIMATE PROJECTIONS, AND ASSET EXPOSURE

The Study Team analyzed historical climate data and future climate projections to evaluate the exposure of PSCo's assets to specific climate hazards throughout the service territory. For each climate hazard included in the assessment, this section describes the historical climate conditions,[4] summarizes future climate projections, and details the resulting exposure scores. Each individual climate hazard variable was scored on a 0 to 5 exposure scale, with 0 representing no exposure and 5 representing the highest exposure. The exposure scoring symbology used to represent results at the asset level is shown in Figure 8.

[4] For extreme heat and frozen precipitation, the historical baseline represents observational data from 1985-2014. For wind, the historical baseline represents observational data from 2008-2024.

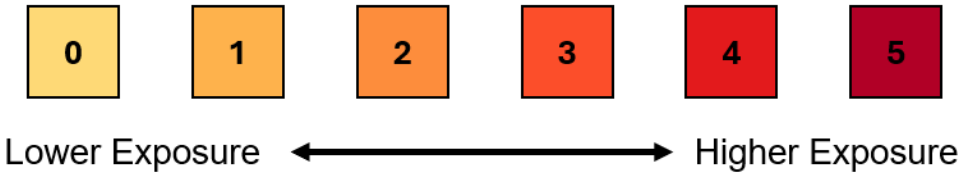


Figure 8. Exposure scoring symbology.

Three asset types were selected to represent and summarize asset exposure for all asset types included in each asset family: (1) overhead conductors were used as a proxy to summarize the exposure results for distribution components, (2) substation transformers were used as a proxy to summarize exposure results for all substation components, and (3) solar panels (Solar PV) were used as a proxy to summarize the exposure results for distributed energy resources (DERs).

The exposure results for all asset types, analyzed climate scenarios, and time horizons are shown in Appendix II. Figure 9 summarizes the highest exposure scores projected by 2050 for any asset under SSP2-4.5 50th percentile projections. Note that exposure is independent of asset sensitivity. Therefore, high exposure does not represent high vulnerability of an asset. Instead, exposure generally represents the projected change in the climate variables associated with each climate hazard in comparison to the historical baseline.

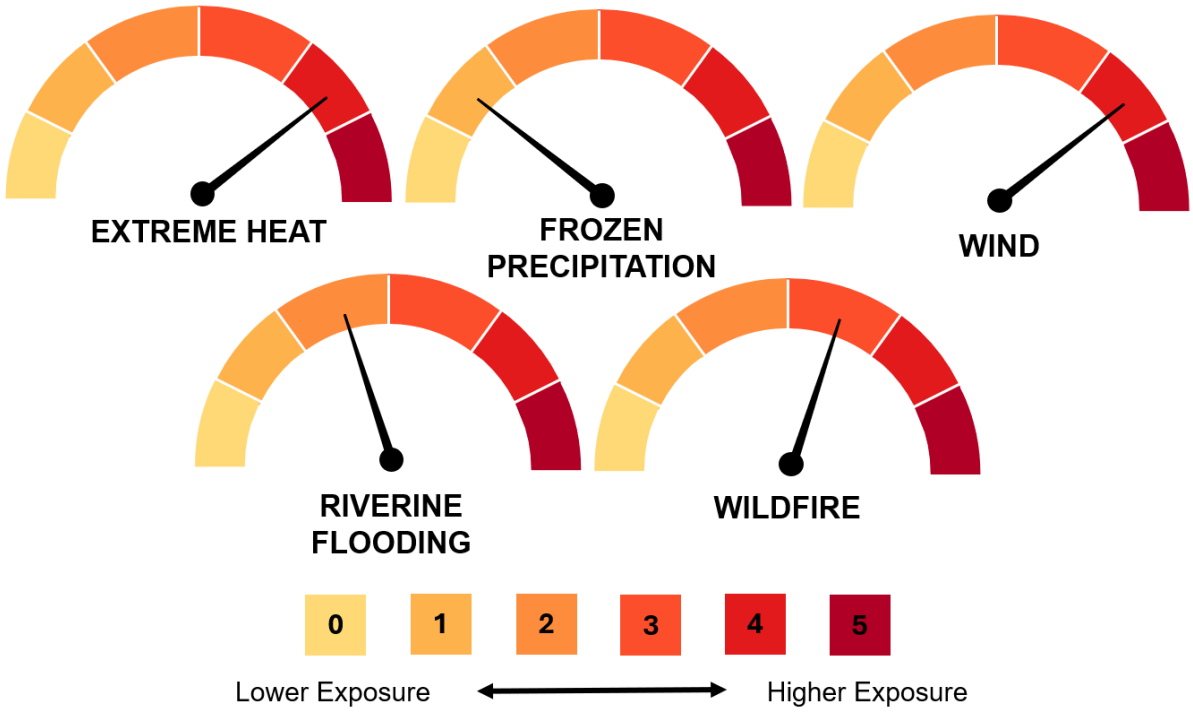


Figure 9. Maximum asset exposure by 2050 (SSP2-4.5 50th percentile) for each climate hazard.

EXTREME HEAT

Historically, Colorado has experienced significant extreme heat events, particularly across the Denver metropolitan area. In recent decades, such events have begun to increase in frequency, severity, and duration across the state.[6] In 2005, a notably intense heat wave hit Colorado. During this event, temperatures at Denver International Airport reached 105°F on July 20th, matching an all-time high. Parts of the Denver metro area reached as high as 108°F.[7] As recently as 2023, Colorado also broke 350 state temperature-related records and tied an additional 165.[8] Colorado's highest temperatures tend to occur in the Arkansas Valley and at lower elevations along the South Platte and Republican Rivers.[9]

To understand present day and future exposure to high temperatures, the Study Team evaluated the following climate variables:

- 30-year daily maximum temperature
- Number of days with maximum temperature over 95°F
- Number of days with maximum temperature over 104°F
- Number of 2-day heat waves with average temperature over 86°F
- Duration of 2-day heat waves with average temperature over 86°F

Thirty-year daily maximum temperatures are projected to increase throughout the century (see Figure 10). By 2050, 30-year daily maximum temperatures are projected to increase from baselines of 73.7°F to 109.9°F across the service territory by ranges of:

- 78.0–114.4°F for SSP2-4.5 50th percentile
- 81.7–119.9°F for SSP5-8.5 90th percentile

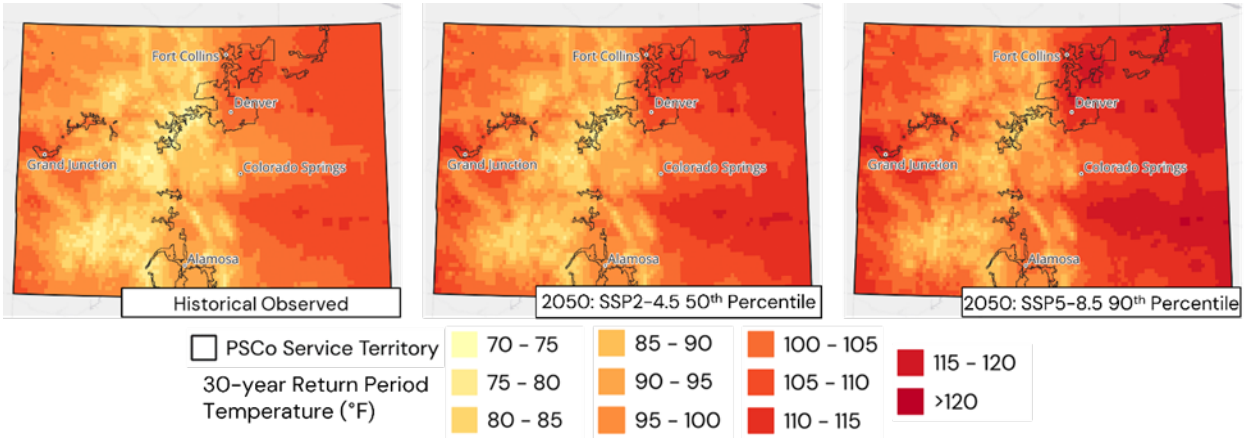


Figure 10. Historically observed and future projections of 30-year daily maximum temperatures across the PSCo service territory.

The number of days with maximum temperatures over 95°F is projected to increase (see Figure 11). By 2050, compared to baselines of 0 to 35.2 days across the service territory, the annual number of days with maximum temperatures over 95˚F is projected to range from:

- 0–69.1 days for SSP2-4.5 50th percentile
- 0–85.9 days for SSP5-8.5 90th percentile

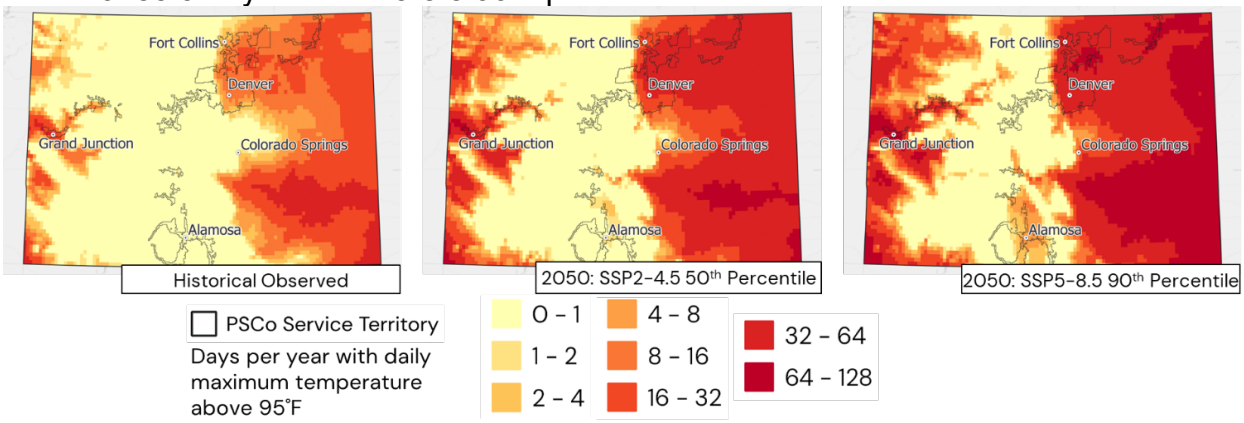


Figure 11. Historically observed and future projections of the number of days per year with daily maximum temperature over 95˚F across the PSCo service territory.

The number of days with maximum temperatures over 104°F is projected to increase (see Figure 12). By 2050, compared to baselines of 0 to 1.4 days across the service territory, the annual number of days with maximum temperatures over 104°F could range between:

- 0–11.6 days for SSP2-4.5 50th percentile
- 0–23.9 days for SSP5-8.5 90th percentile

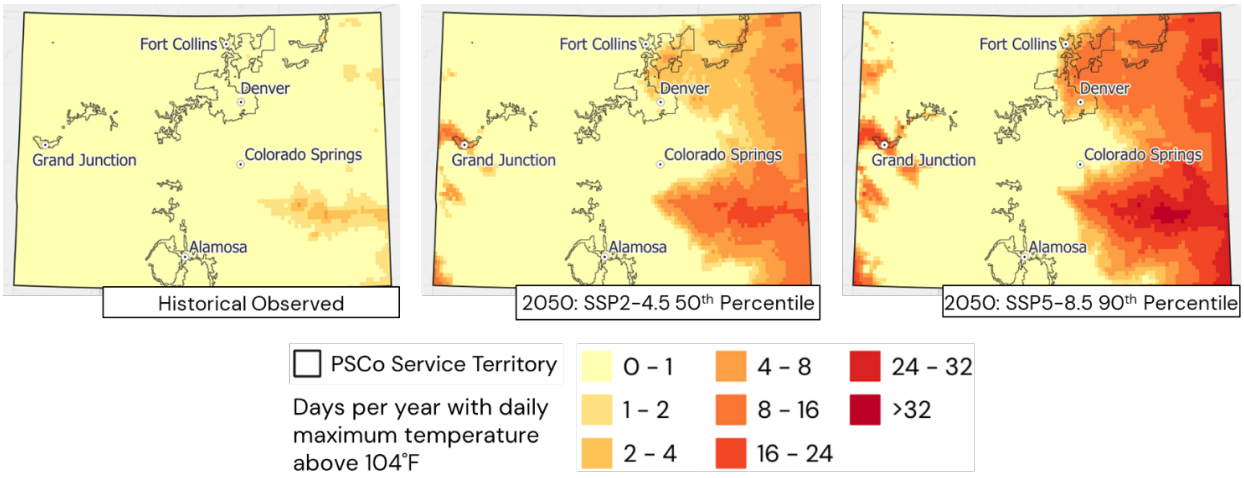


Figure 12. Historically observed and future projections of the number of days per year with daily maximum temperature over 104˚F across the PSCo service territory.

The number of heat waves lasting 2 days or more and exceeding a daily average temperature of 86°F is projected to increase (see Figure 13). By 2050, compared to a baseline of 0–0.6 heat waves across the service territory, the number of heat waves is projected to range between:

- 0–4.0 heat waves for SSP2-4.5 50th percentile
- 0–5.4 heat waves for SSP5-8.5 90th percentile

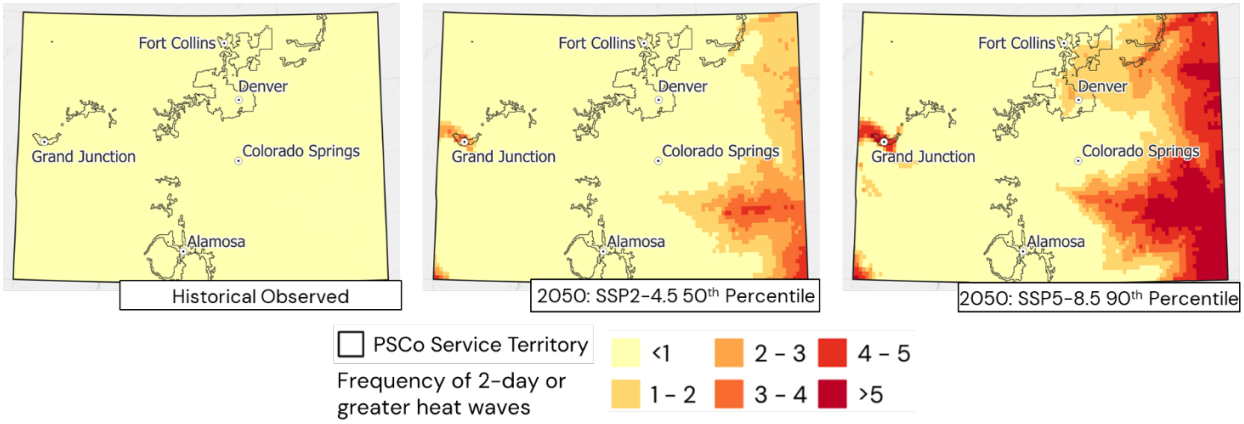


Figure 13. Observed and projected frequency of 2-day or greater heat waves across the PSCo service territory.

The duration of heat waves lasting 2 days or more and exceeding a daily average temperature of 86˚F is also projected to increase (see Figure 14). By 2050, compared to a baseline of 0–1.6 days across the service territory, the duration of heat waves is projected to range between:

- 0–8.4 days for SSP2-4.5 50th percentile
- 0–16.5 days for SSP5-8.5 90th percentile

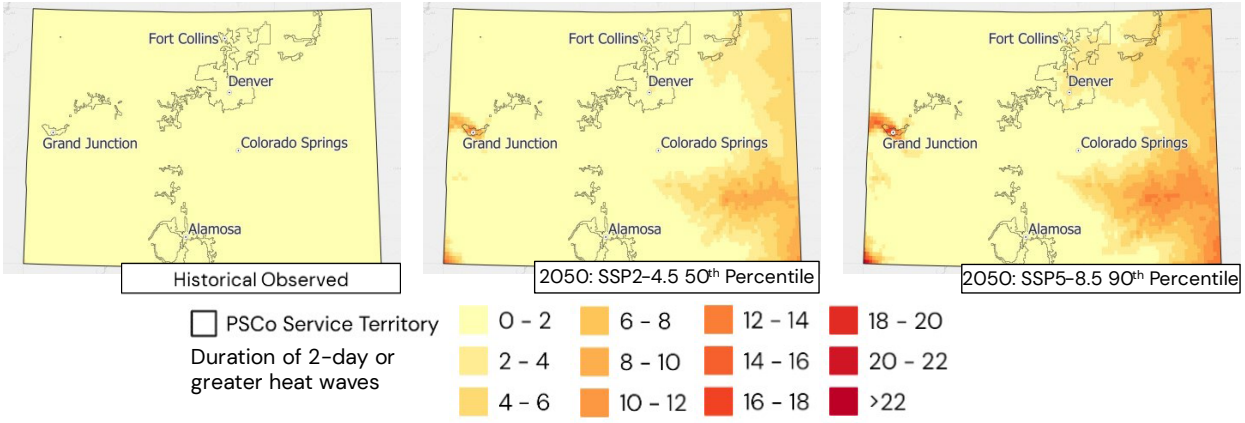


Figure 14. Observed and projected duration of 2-day or greater heat waves across the PSCo service territory.

Average and extreme temperatures are projected to increase across the PSCo service territory by 2050 under both SSP2-4.5 and SSP5-8.5 emissions scenarios. Notably, changes in extreme heat will be more pronounced under the higher emissions climate scenario (SSP5-8.5) and higher percentile projections. The greatest warming is projected to occur in the eastern part of the state and along the western and southwestern border. The extreme heat exposure score was arrived at by averaging the individual score of each of the analyzed climate variables. Each climate variable was scored with the rubric shown in Table 3.

Table 3. Extreme heat exposure scoring rubric.

	Extreme Heat									
Variable Weight	20%		20%		20%		20%		20%	
Variable	*30-year daily maximum temperature*		*Number of days with maximum temperature over 95*		*Number of days with maximum temperature over 104*		*Number of 2-day heatwaves with average temperature over 86F*		*Duration of 2-day heatwaves with average temperature over 86F*	
Thresholds	Magnitude (F)	Exposure Score	Days	Exposure Score	Days	Exposure Score	Count	Exposure Score	Days	Exposure Score
	<95	0	<1	0	<1	0	<1	0	<2	0
	95–104	1	1–3	1	1–2	1	1–2	1	2–3	1
	104–110	2	3–5	2	2–4	2	2–3	2	3–5	2
	110–115	3	5–10	3	4–7	3	3–4	3	5–10	3
	115–120	4	10–20	4	7–10	4	4–5	4	10–15	4
	120+	5	20+	5	10+	5	5+	5	15+	5

Figure 15 summarizes the extreme heat exposure results across the counties in the service territory for SSP2-4.5 50th percentile by 2050. This indicates that while temperatures are projected to increase, most assets might not experience extreme temperatures exceeding current design standards and operation thresholds. Nevertheless, assets sensitive to high temperatures within Mesa, Weld, and Logan counties might require intervention to adapt to future conditions. Asset sensitivity to extreme heat is discussed in the Vulnerability Assessment section.

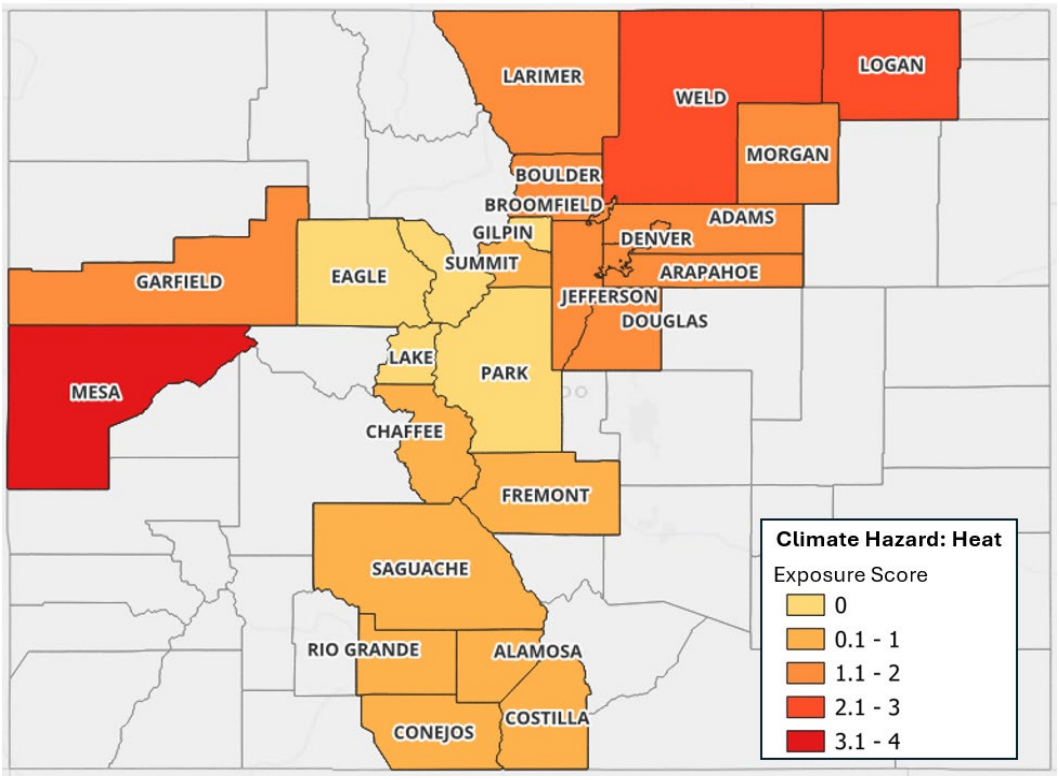


Figure 15. Maximum heat exposure scores by county by 2050 (SSP2-4.5 50th percentile).

The extreme heat exposure score at the individual-asset level is summarized in Figure 16 for three representative assets: (1) solar panels (Solar PV), (2) overhead conductors, and (3) substation transformers. By midcentury, these representative assets' extreme heat exposure scores are projected to be mostly 2 or lower. Higher scores indicate that some assets may experience extreme heat conditions at higher magnitudes, duration, and/or frequency.



Figure 16. Projected percent of Solar Panel, Overhead Conductor, and Substation Transformer assets exposed to extreme heat in 2030, 2050, and 2080 under the SSP2-4.5 50th percentile scenario.

FROZEN PRECIPITATION

Historically, Colorado has experienced ice storms that have led to significant ice accumulations. Ice accumulation has the potential to severely impact assets and operations and to affect general infrastructure and transportation. For example, in 2005, a winter storm brought heavy snow and ice to parts of southeastern Colorado.[10] The areas affected during this 2005 ice storm included the eastern Las Animas County, eastern Kiowa County, and La Junta municipality. More recently, in 2017, there was a notable ice storm that led to significant ice accumulation on roads and power lines between Clark, CO, and the west side of Steamboat Springs.[11] In some parts of Colorado, ice accumulation reached up to 0.5 inches.[12] The event was driven by a Pacific storm system that produced freezing rain in Colorado.[13] The ice accumulation that resulted from this storm created widespread power outages near Durango and Steamboat Springs.[14]

Maximum daily frozen precipitation intensity across the service territory has a historical baseline ranging from 0.2 to 1.8 inches. While climate change is driving warmer temperatures across PSCo's service territory, this does not preclude the potential for frozen precipitation events to continue to occur in the future. To understand present day and future exposure to frozen precipitation, the Study Team evaluated the projected change in maximum daily frozen precipitation intensity (Figure 17).

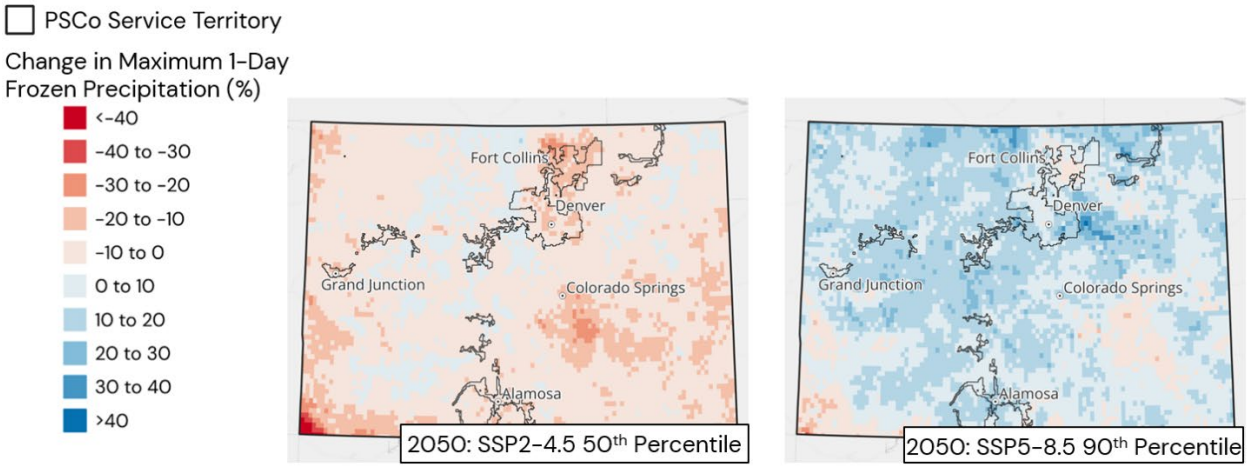


Figure 17. Projected percent change in the maximum 1-day frozen precipitation amounts by 2050 across the PSCo service territory.

By 2050 and relative to observed frozen precipitation intensity, the change of maximum daily frozen precipitation intensity throughout Colorado range between:

- -26.3% to 7.4% for SSP2-4.5 50th percentile
- -8.0% to 34.3% for SSP5-8.5 90th percentile

The scoring criteria rubric is shown in Table 4.

Table 4. Frozen precipitation exposure scoring rubric.

	Frozen Precipitation	
Variable Weight	100%	
Variable	*Maximum daily frozen precip.*	
Thresholds	Percent Change	Exposure Score
	<= 0%	0
	0–5% increase	1
	5–10% increase	2
	10–20% increase	3
	20–30% increase	4
	>30% increase	5

A large proportion of the service territory is projected to experience a decrease in frozen precipitation under the lower emissions scenario (see Figure 17). Frozen precipitation is projected to increase under a higher emissions scenario throughout a greater proportion of the service territory. Frozen precipitation exposure is highest in the area surrounding Denver, likely driven by increased precipitation intensities with climate change and despite warming temperatures that reduce the likelihood of days with frozen precipitation. Figure 18 summarizes the frozen precipitation exposure results across the counties in the service territory for SSP2-4.5 50th percentile by 2050.

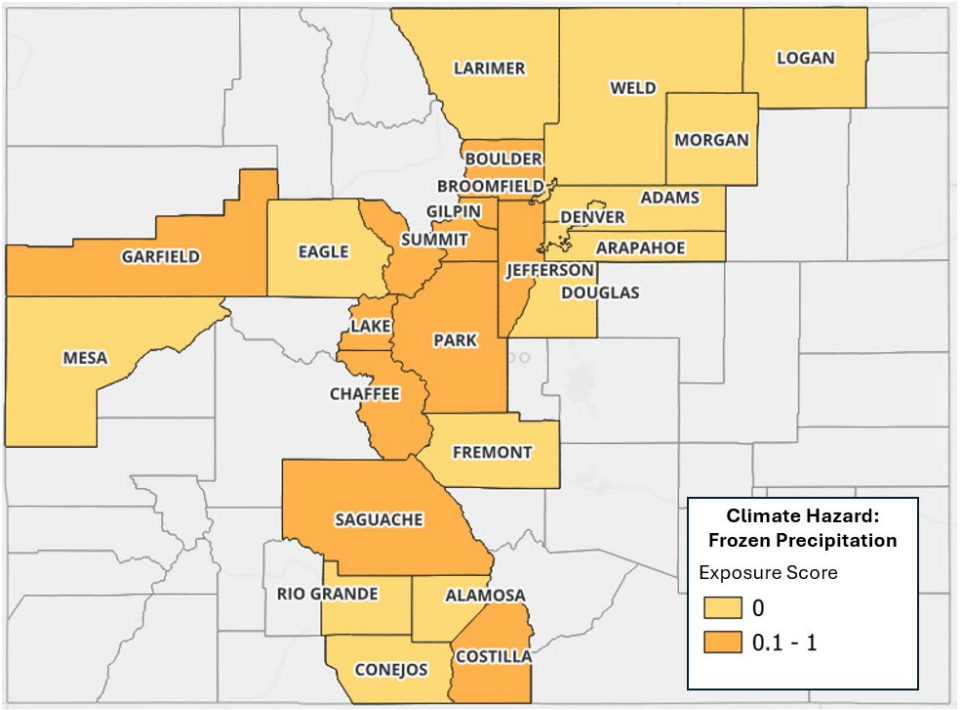


Figure 18. Maximum frozen precipitation exposure scores (SSP2-4.5 50th percentile) by county by 2050.

The frozen precipitation exposure score at the individual-asset level is summarized in Figure 19 for three representative assets: (1) solar panels (Solar PV), (2) overhead conductors, and (3) substation transformers. In all time horizons under the SSP2-4.5 50th, these representative assets' frozen precipitation exposure scores are projected to be 1 or lower. This can be interpreted as little to no change in comparison to historical frozen precipitation conditions or a change toward more favorable conditions in this hazard (i.e., fewer frozen precipitation events). Asset sensitivity to frozen precipitation is discussed in the Vulnerability Assessment section below.

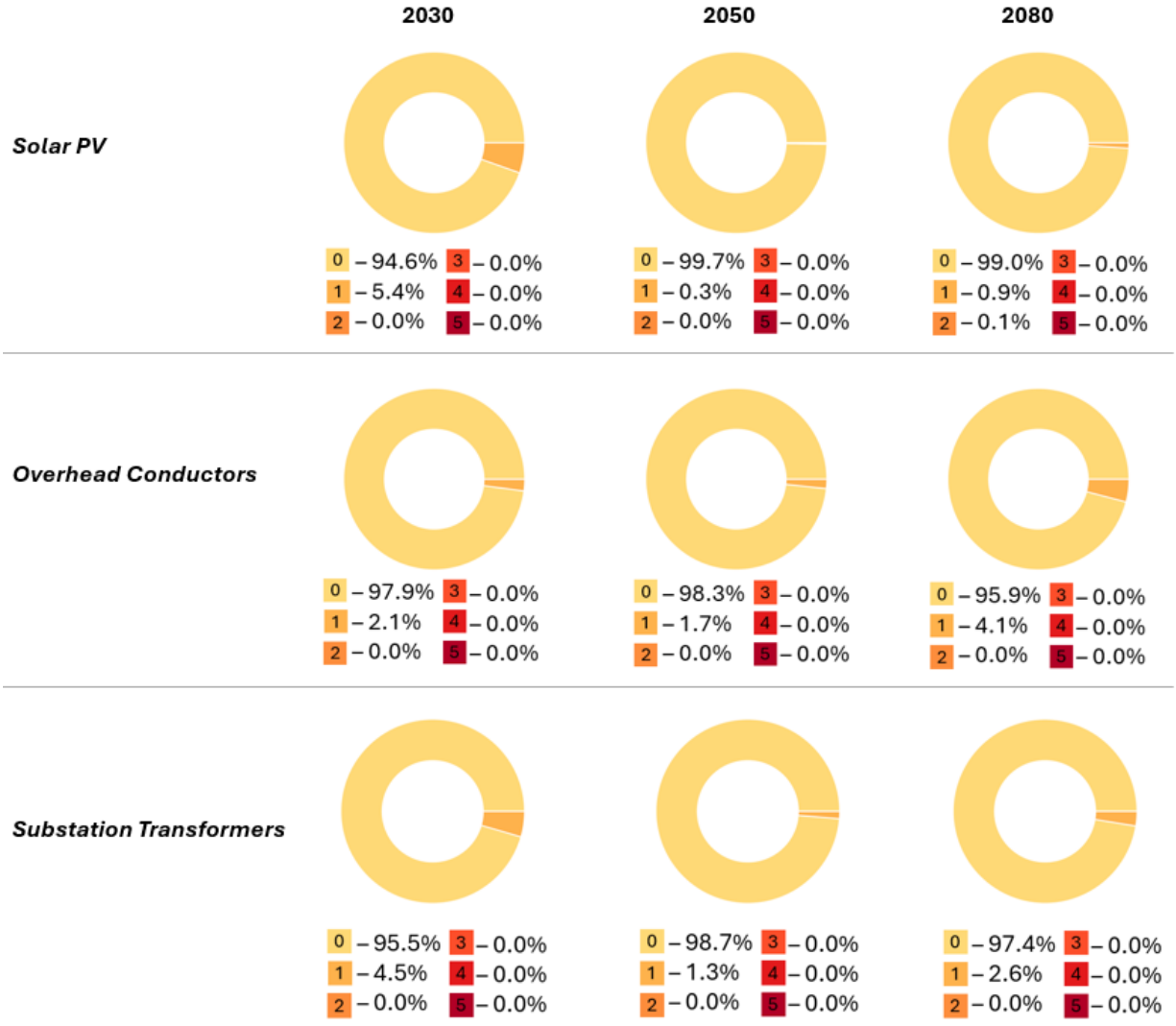


Figure 19. Projected percent of Solar Panel, Overhead Conductor, and Substation Transformer assets exposed to ice in 2030, 2050, and 2080 under the SSP2-4.5 50th percentile scenario.

EXTREME WIND

Historically, extreme wind risk is highest in portions of Denver, Boulder, and Larimer counties in northern Colorado (Figure 20), according to the FEMA National Risk Index[15]. In the past, Colorado has experienced extreme wind events with maximum wind gusts reaching over 100 mph. High wind speeds across Colorado are partly related to the state's topography, with mountains constricting the flow of air and driving increases in wind speed.[16] In February 2016, the state record for maximum wind speed was recorded at 148 mph on top of Monarch pass[17]. In December 2021, Southern Colorado also experienced a major windstorm, with wind speeds in Pueblo approaching 100 mph.[18] As recently as early April 2024, a windstorm swept across Colorado and resulted in widespread, prolonged power outages, including across the PSCo service territory. During this event, winds across the state reached nearly 100 mph in higher elevation areas, as well as nearly 70 mph at the Rocky Mountain Regional Airport.[19]

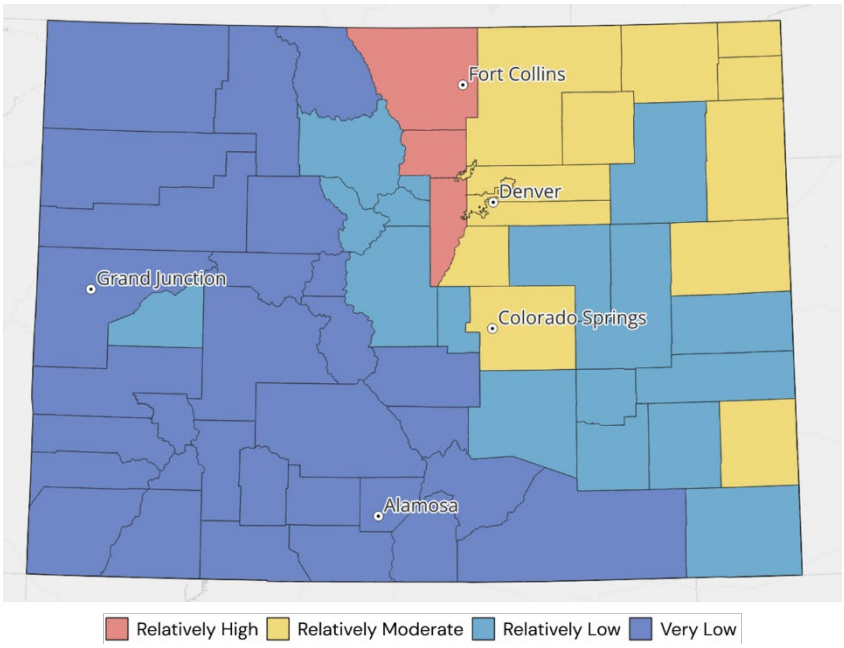


Figure 20. FEMA's National Risk Index (NRI) Strong Wind Risk Categorization for counties across Colorado.

Wind is not projected to change significantly across the PSCo service territory. Some areas are projected to experience an increase in wind speeds by midcentury while others may experience a decrease (see Figure 21). By 2050 and relative to observed values, the change in annual number of days with average wind speeds above the historical 90th percentile values in Colorado could range between:

- -3.5 to -2.2 for SSP2-4.5 50th percentile
- -1.5 to +0.9 for SSP5-8.5 90th percentile

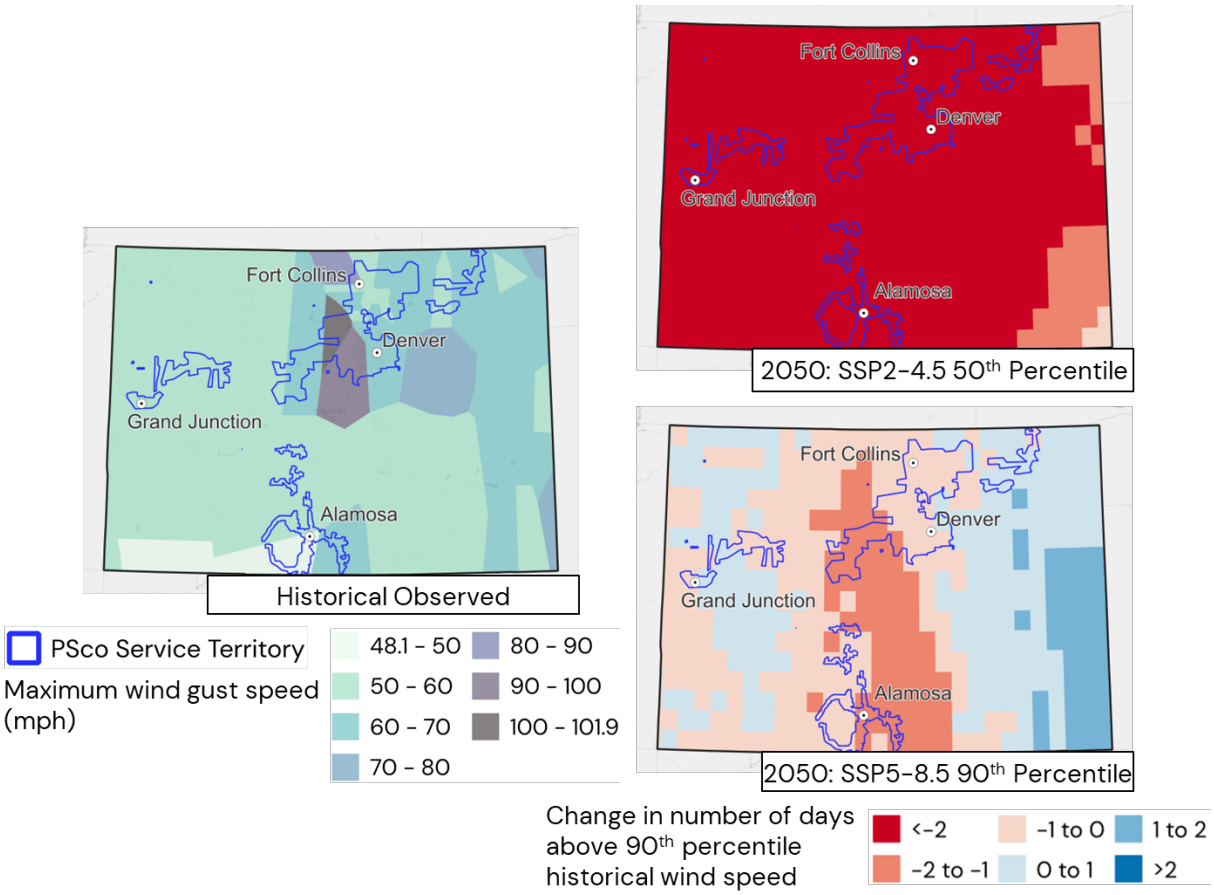


Figure 21. Observed maximum wind gust speed is shown on the left. The projected change in the number of annual days with average wind speeds above the 90th percentile historical average wind speeds by 2050 across the PSCo service territory is shown on the right.

While daily averaged wind speeds may not change significantly, peak wind gusts could increase with climate change. The space and time scales at which wind gusts occur are not typically well-resolved in climate models, leading to a high degree of uncertainty in the magnitude of future extreme wind gust trends. The most extreme wind gust events, however, are expected to increase in intensity and frequency with climate change.

To understand present day and future exposure to extreme wind, PSCo evaluated the following variables for the vulnerability assessment:

- Historical maximum wind gusts
- Number of days with 1-day average wind speed above historical 90th percentile

The wind exposure score was calculated by assigning 80% and 20% weights to historical and projected wind, respectively, as shown in Table 5.

Table 5. Extreme Wind exposure score rubric.

	Extreme Wind			
Variable Weight	80%		20%	
Variable	*Historical maximum wind gusts*		*Number of days with 1-day avg wind speed above historical 90th percentile*	
Thresholds	MPH	Exposure Score	Change in Days	Exposure Score
	0–35 MPH	0	<= 0 change in days	0
	35–50 MPH	1	0–1 day increase	1
	50–60 MPH	2	1–3 day increase	2
	60–70 MPH	3	3–5 day increase	3
	70–90 MPH	4	5–7 day increase	4
	90+ MPH	5	7+ day increase	5

Despite minimal changes in average wind speeds, exposure to the most extreme wind gusts could be a concern in wind-prone locations. By midcentury, nearly all areas will be exposed to scores of 2 to 4 (see Figure 22). Wind exposure will be highest in the higher elevation areas west of Denver. Higher wind exposure scores are driven by historically high wind gusts in these areas. The counties surrounding Denver and Alamosa have higher wind exposure scores by 2050 under a high emissions scenario.

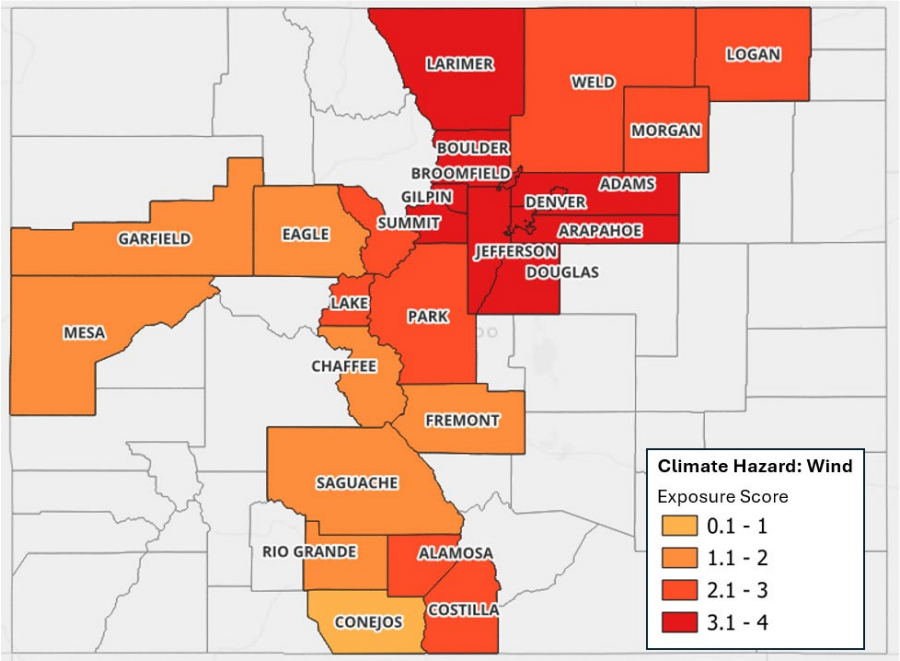


Figure 22. Maximum wind exposure scores (SSP2-4.5 50th percentile) by county by 2050.

The wind exposure score at the individual-asset level is summarized in Figure 23 for three representative assets: (1) photovoltaic panel installations (solar panels), (2) overhead conductors, and (3) substation transformers. Throughout all time horizons, at least 30% of these representative assets' wind exposure scores are projected to be 4. Since the wind exposure score is mostly driven by historical exposure, the higher exposure results can be interpreted as locations where assets are likely to experience high-wind conditions. Asset sensitivity to extreme wind is discussed in the Vulnerability Assessment section.

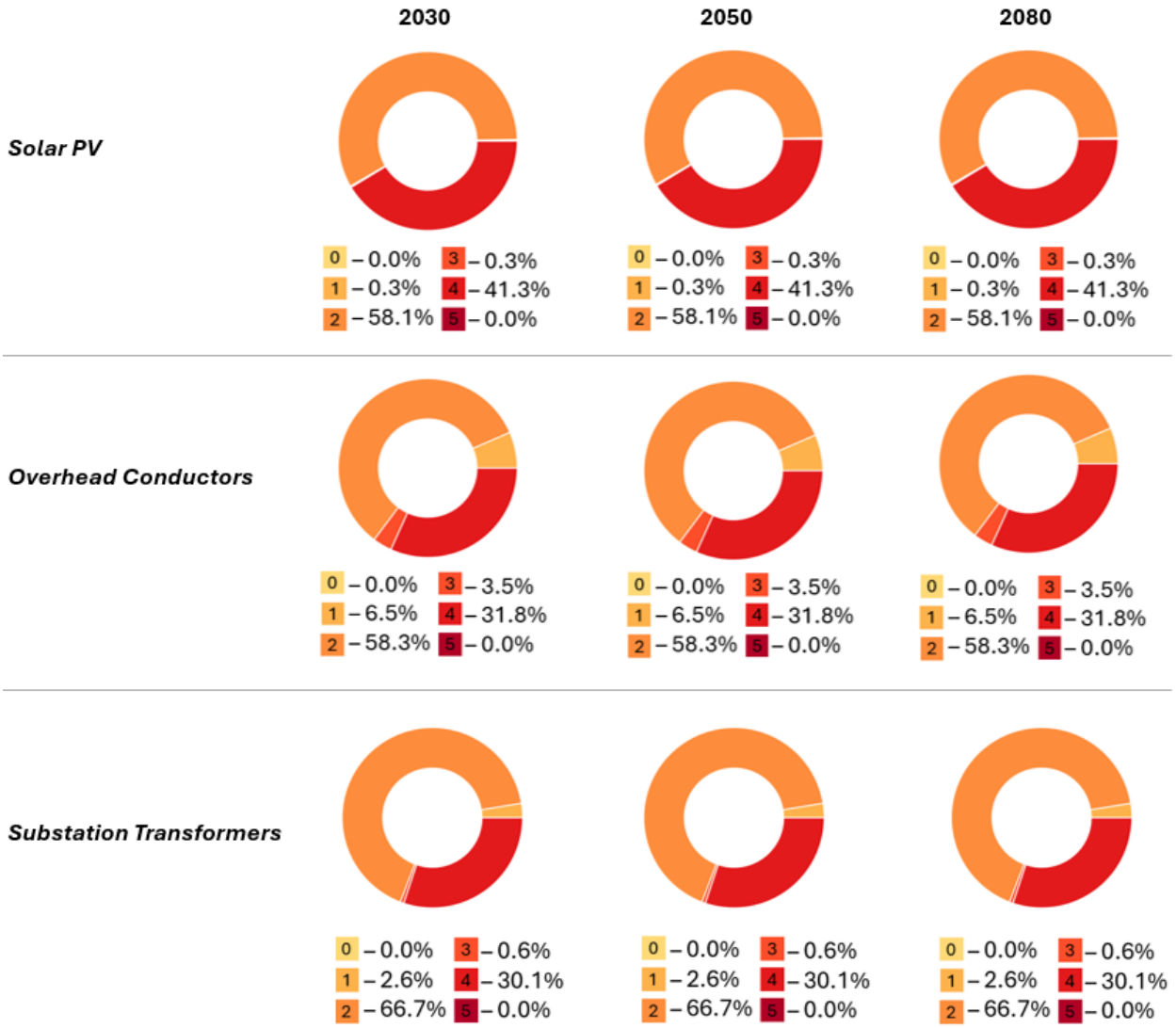


Figure 23. Projected percent of Solar Panel, Overhead Conductor, and Substation Transformer assets exposed to wind gusts by 2030, 2050, and 2080 under the SSP2-4.5 50th percentile scenario.

RIVERINE FLOODING

Riverine flooding, which occurs when streams and rivers overflow their banks, has historically been one of the most widespread natural hazards in Colorado.[20] Inland flood risk is typically highest in areas surrounding the Platte River and its tributaries in the South Platte water basin in northeastern Colorado, primarily in Boulder, Weld, and Larimer counties, as demonstrated by 100- and 500-year FEMA floodplain extent in Figure 24.

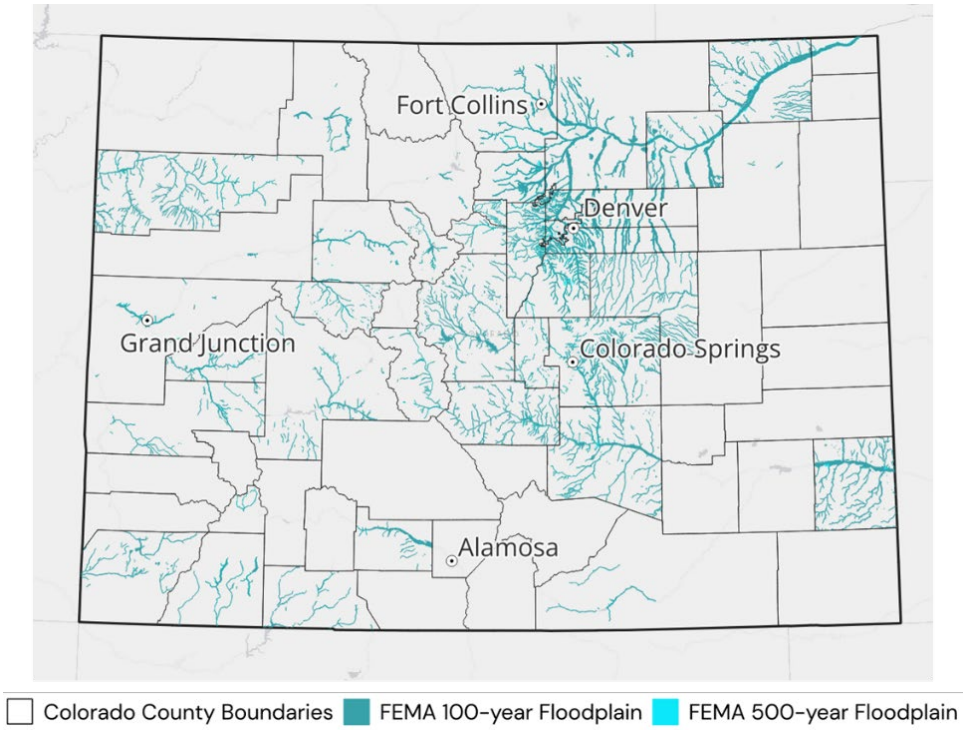


Figure 24. Present-day 100- and 500-year FEMA floodplain extent with respective 1% and 0.2% annual flood probabilities across Colorado, where available.

Tributaries of the Colorado River in northwestern Colorado, Rio Grande River in southern Colorado, and Arkansas River in southeastern Colorado are susceptible to severe riverine flooding during extreme precipitation events. For instance, a major riverine flooding event occurred in September 2013 when heavy precipitation hit Colorado's Front Range. This event resulted in nine deaths, more than 10,000 evacuations, thousands of lost homes, and billions of dollars in damages across the state.[21] Boulder County was hit the hardest during this event, including the towns of Lyons, Boulder, Lafayette, and Louisville, all of which are part of PSCo's service territory. By the end of the event, Boulder County had recorded 18.1 inches of rain over 7 days and Larimer County had recorded 12.4 inches of rain over the same period.[22]

Climate change is projected to drive increases in inland flooding as precipitation becomes more variable and intense, especially under high-end scenarios. Extreme precipitation is projected to increase in most areas throughout Colorado (Figure 25). Intense bursts and prolonged precipitation drive inland flooding, particularly within and next to present-day

100- and 500-year floodplains. To understand present day and future exposure to riverine flooding, PSCo evaluated the following variables for the vulnerability assessment:

- 500-year floodplain
- 100-year floodplain
- Annual maximum 5-day precipitation

Observed annual maximum 5-day precipitation across the service territory ranges from 1.0 to 4.2 inches. By 2050, annual maximum 5-day precipitation could change (relative to baseline) by:

- -2.9% to 8.6% for SSP2-4.5 50th percentile
- 7.6% to 38.8% for SSP5-8.5 90th percentile

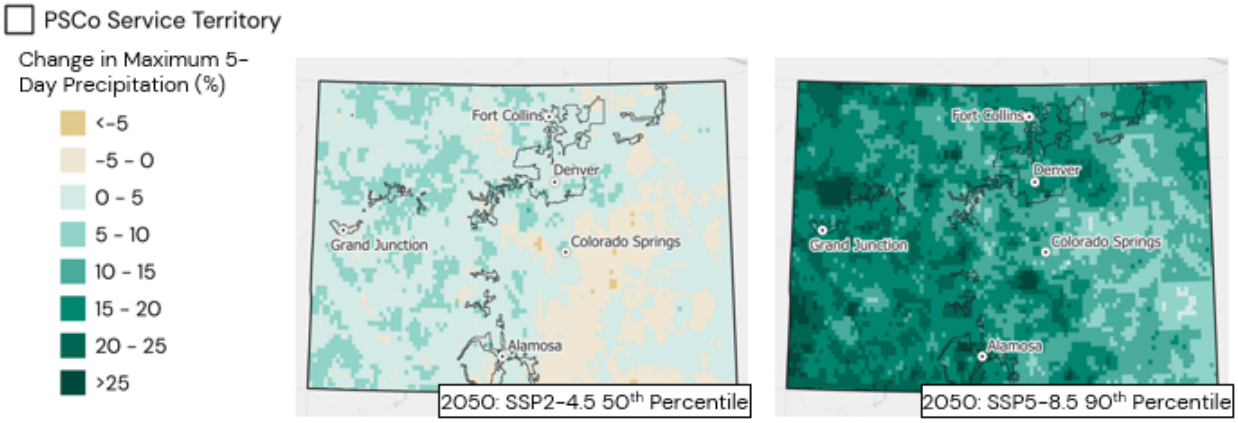


Figure 25. Projected percent change in the maximum 5-day precipitation by 2050 across the PSCo service territory.

The western half of Colorado is projected to see the greatest increase in heavy precipitation under both future climate scenarios. Additionally, floodplains across the state are projected to expand due to increasingly extreme precipitation. Riverine flooding exposure score was established as the average score of: (1) assets within the 500-year floodplain, but not in the 100-year floodplain, and associated percent increase in annual maximum 5-day precipitation and (2) assets within the 100-year floodplain and associated percent increase in annual maximum 5-day precipitation (see Table 6).

Table 6. Riverine flooding exposure score rubric.

	Riverine Flooding			
Variable Weight	50%		50%	
Variable	*500-yr floodplain (and not in 100 flood) + annual max. 5-day precip.*		*100-yr floodplain + annual max. 5-day precip.*	
Thresholds	In floodplain or out + Percent Change	Exposure Score	In floodplain or out + Percent Change	Exposure Score
	No floodplain (precipitation irrelevant)	0	No floodplain (precipitation irrelevant)	0
	500-yr floodplain (no % increase)	1	100-yr (no % increase)	1
	500-yr floodplain (0-10% increase)	2	100-yr floodplain (0-10% increase)	2
	500-yr floodplain (10-20% increase)	3	100-yr floodplain (10-20% increase)	3
	500-yr floodplain (20-30% increase)	4	100-yr floodplain (20-30% increase)	4
	500-yr floodplain (>30% increase)	5	100-yr floodplain (>30% increase)	5

For riverine flooding, an exposure score of 1 indicates that the asset is already in either the present-day 100- or 500-year floodplain, which would highlight the need to intervene with flood mitigation measures. Figure 26 shows an example of pad-mount transformers in current-day floodplains which is approximately 2% of all pad-mount transformers.

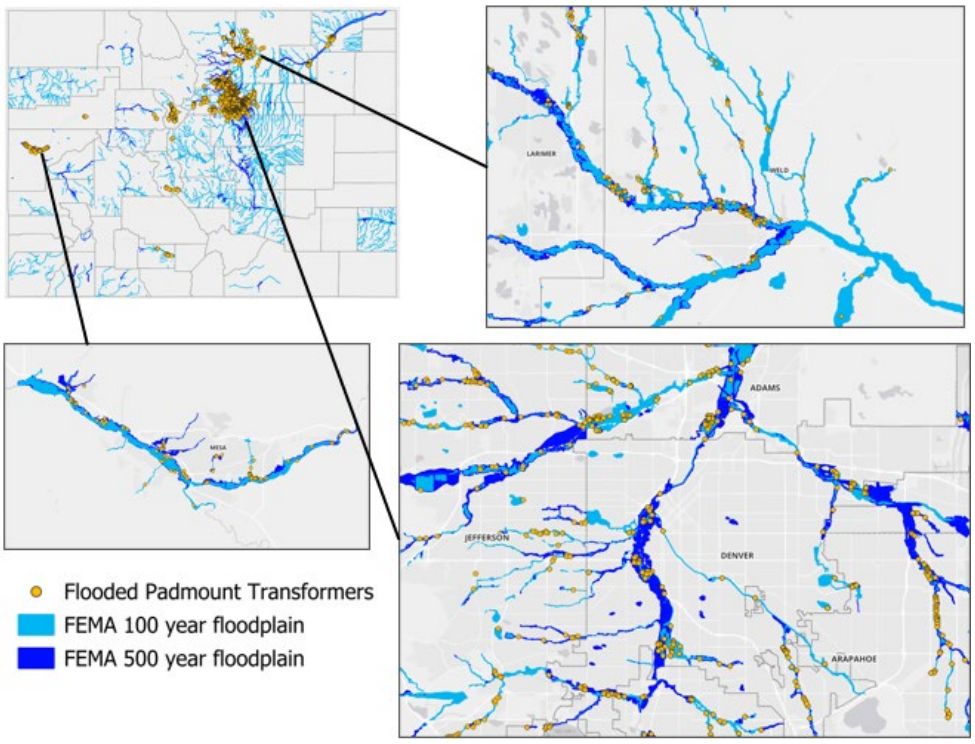


Figure 26. Pad mount transformers in the FEMA 100- and 500-year floodplains.

The increase in precipitation is associated with exacerbating current-day floodplains in extent and/or depth, thus increasing the exposure score. The riverine flooding exposure score at the individual-asset level is summarized in Figure 27 for three representative assets: (1) photovoltaic panel installations (solar panels), (2) overhead conductors, and (3) substation transformers. By midcentury, a growing number of assets might be exposed to riverine flooding, with exposure scores up to 2. Asset sensitivity to riverine flooding is discussed in the Vulnerability Assessment section.

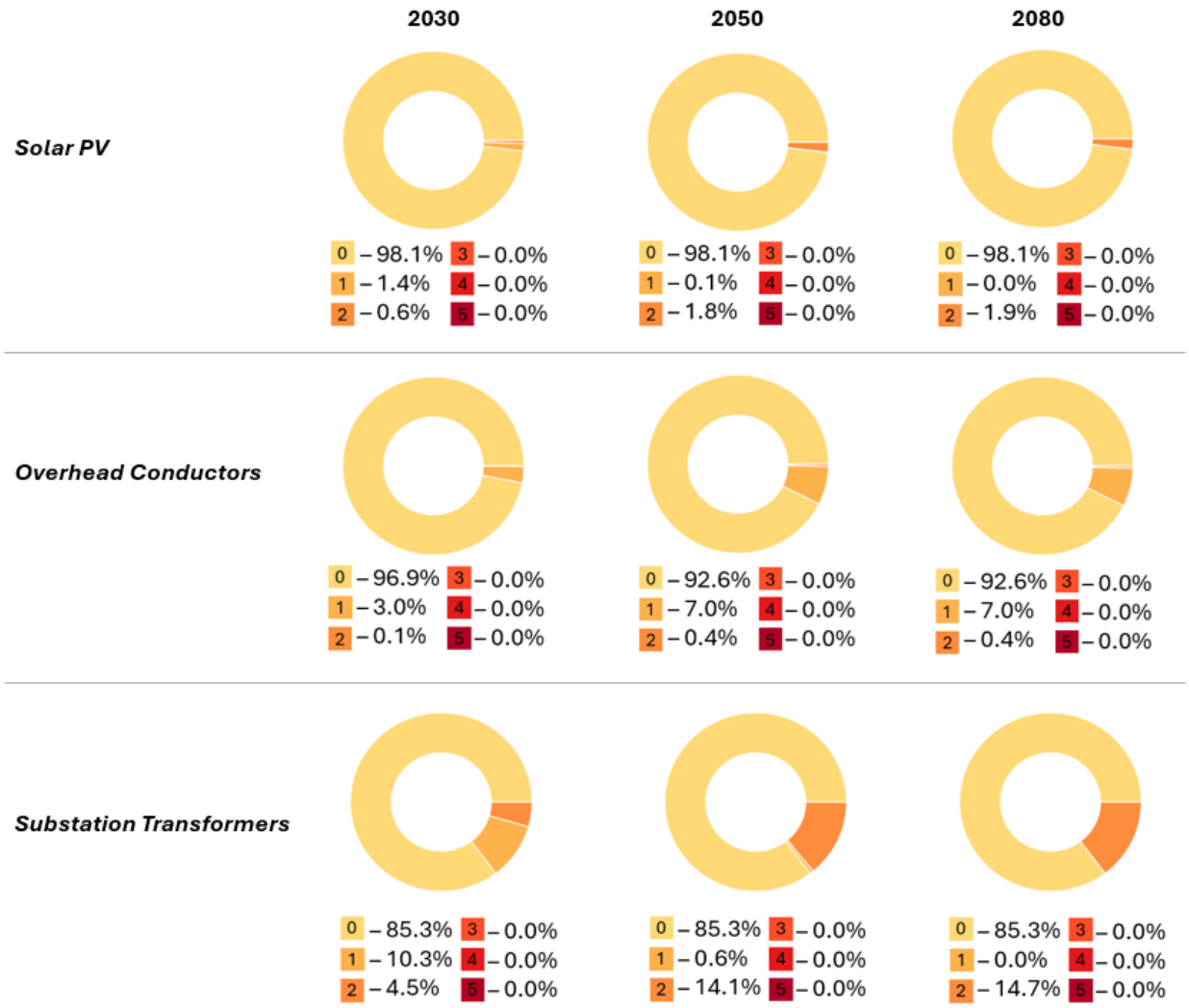


Figure 27. Projected percent of Solar Panel, Overhead Conductor, and Substation Transformer assets exposed to riverine flooding in 2030, 2050, and 2080 under the SSP2-4.5 50th percentile scenario.

WILDFIRE

Historically, wildfire likelihood is highest in the mountainous, forested areas of Colorado, along the Front Range west of Denver and the Colorado Plateau in western Colorado (Figure 28). In the past, Colorado has experienced wildfires that have led to widespread destruction, costly damages, and even deaths.[23] Across the state, wildfires are generally associated with regional drought conditions and the largest fires in the state's history have all occurred since 2002.[24] Homes in areas of Denver, Boulder, Pueblo, and Fort Collins, all located in PSCo's service territory, have been identified as being particularly at risk of wildfires; especially as the wildland urban interface continues to expand.[25] The largest wildfire by acreage occurred in 2020 near Cameron Pass and burned for nearly four months, ultimately consuming 208,913 acres of land.[26] In 2021, Colorado also experienced its most destructive wildfire when the Marshall Fire swept across Boulder County, consuming more than 1,000 homes.[27] Notably, while there are times of year where the risk of wildfire may be higher, climate change is extending the traditional wildfire season and wildfires are now occurring during all seasons of the year.

To understand present day and future exposure to wildfire, PSCo evaluated the following variables for the vulnerability assessment:

- Historical fire weather probabilities
- Annual change in the number of days above the 95th percentile FWI

The historical relative wildfire likelihood was obtained from the U.S. Forest Service (USFS) Wildfire Risk to Communities dataset[28], shown in Figure 28.

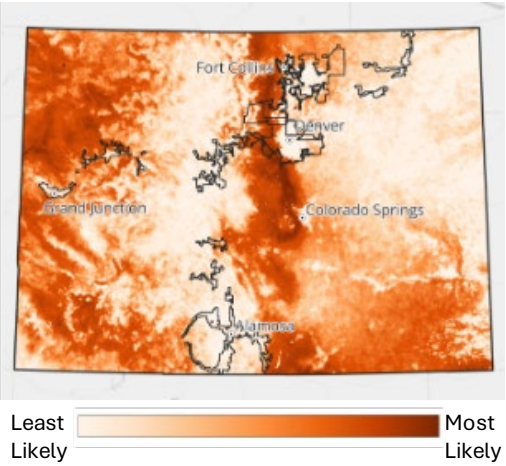


Figure 28. Historical relative wildfire likelihood across Colorado, from the USFS Wildfire Risk to Communities Dataset.

Weather conditions are projected to become more favorable for fire development and spread as temperatures warm in the future. Drawing on data from the Canadian Forest Fire Weather Index (FWI), projections suggest that summer days above historical annual 95th percentile FWI are projected to change by 2050 across the service territory (Figure 29), with the largest increases in the higher-end scenarios caused by increased warming trends.

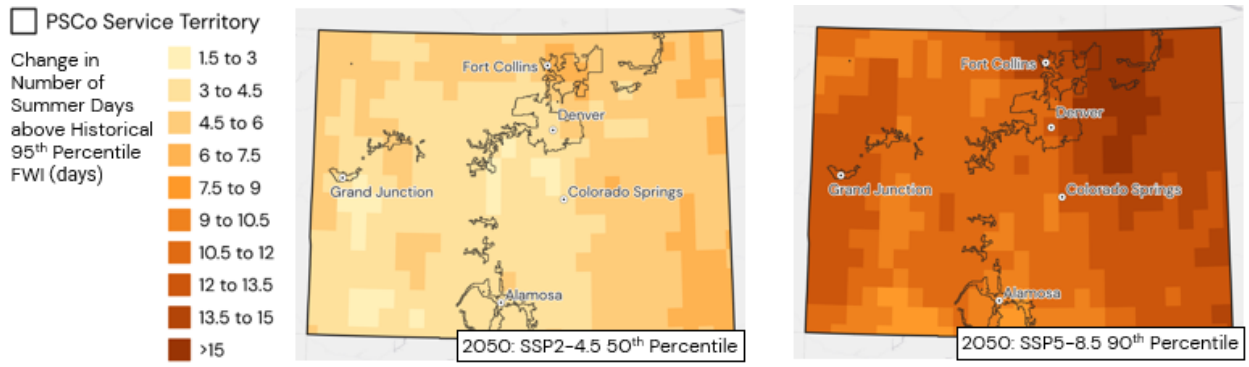


Figure 29. Projected change in the number of summer days above historical 95th percentile FWI by 2050 across the PSCo service territory.

By 2050, the number of days above historical annual 95th percentile FWI (relative to baseline) could change by:

- 3.8 to 13 days for SSP2-4.5 50th percentile
- 12.6 to 30.8 days for SSP5-8.5 90th percentile

The wildfire exposure score was calculated as the average between the change in number of days above the 95th percentile FWI and historical fire weather probabilities scores, as shown in Table 7.

Table 7. Wildfire exposure scoring rubric.

	Wildfire			
Variable Weight	50%		50%	
Variable	*Annual change in the number of days above 95th percentile FWI*		*Historical fire weather probabilities*	
Thresholds	Change in Days	Exposure Score	Fire Weather Probabilities	Exposure Score
	<= 0 day increase	0	Probability = 0	0
	0–5 day increase	1	0–0.0025	1
	5–15 day increase	2	0.0025–0.005	2
	15–25 day increase	3	0.005–0.0075	3
	25–40 day increase	4	0.0075–0.01	4
	> 40 day increase	5	>0.01	5

Warming temperatures and changes in wind and precipitation patterns will likely drive increased likelihood of high fire danger days across the PSCo service territory, especially in regions that have historically experienced wildfires. Wildfire exposure is projected to be

highest west of Denver in the foothills of the Front Range, where historical wildfire occurrence is highest (see Figure 30).

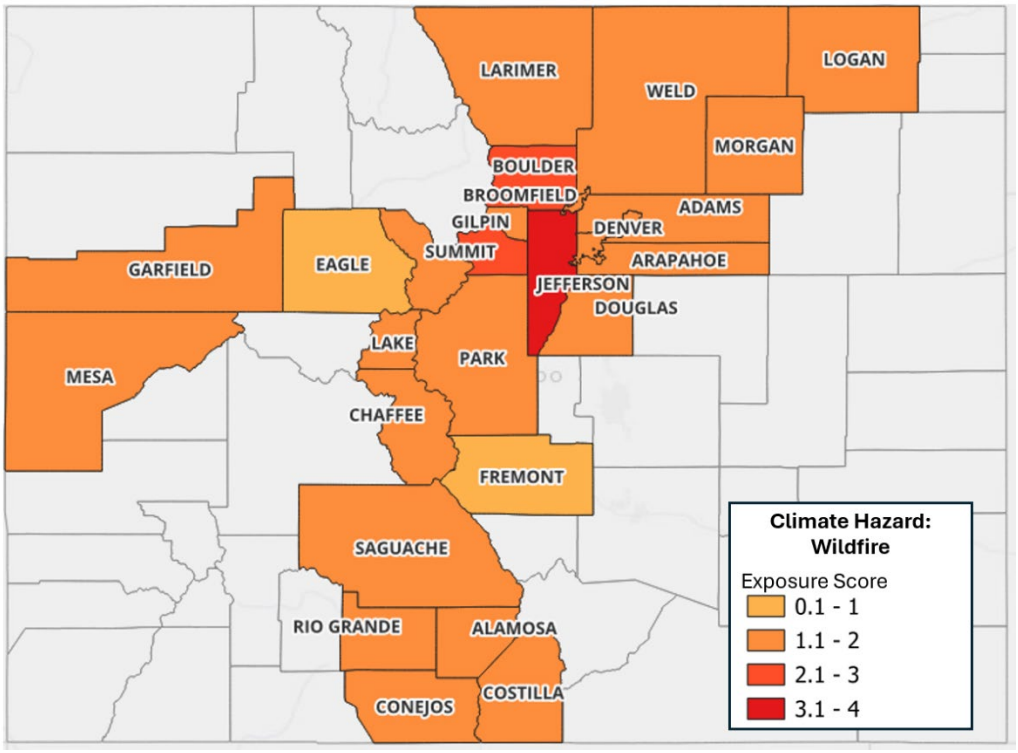


Figure 30. Maximum wildfire exposure scores (SSP2-4.5 50th percentile) by county by 2050.

By midcentury, 22.4% of overhead conductors, 51.9% of poles, and 63.5% of transformers are projected to be exposed to wildfire with exposure scores of 2 or higher (Figure 31). This represents an increase in the number of days with potential wildfire conditions. Asset sensitivity to wildfire is discussed in the Vulnerability Assessment section.

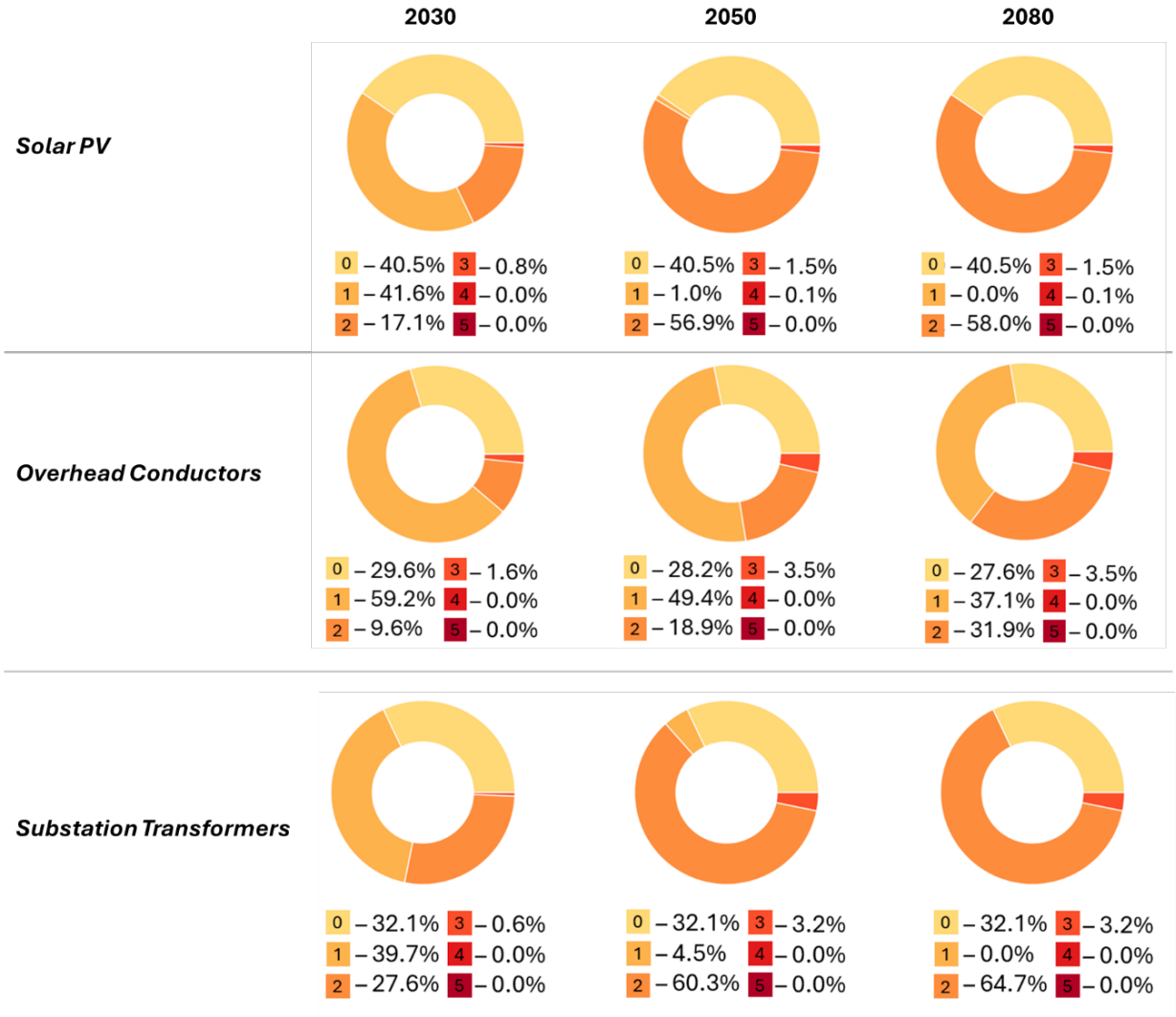


Figure 31. Projected percent of Solar Panel, Overhead Conductor, and Substation Transformer assets exposed to wildfire in 2030, 2050, and 2080 under the SSP2-4.5 50th percentile scenario.

EXTREME EVENTS: COLD SNAPS AND POLAR VORTEX EVENTS

In addition to the climate hazards explored above, Colorado has also experienced impacts from cold snaps and avalanches. For example, a 2022 cold snap event resulted in temperatures dropping to as low as -24°F in the Denver metro area,[29] a 2021 cold snap resulted in 12 consecutive days below freezing temperature (32˚F) in Denver,[30] and a February 1996 cold snap event impacted much of the southeast plains region and brought bitterly cold temperatures to many different parts of Colorado.[31]

Avalanches, the rapid flow of masses of snow down a slope, are another extreme event that can impact portions of Colorado. Avalanches can directly impact assets leading to damage, failure, or impede access to assets. For example, in March 2019, Xcel Energy recorded an outage to a transmission line segment near Dillon, CO, where an avalanche made the access roads to the outage location impassable.[32] Avalanches are harder to

forecast than other climate variables but are important to be aware of given their destructive power. Other extreme events that have impacted Colorado include tornadoes, severe thunderstorms, flash flooding, and powerful winter storms.

Given the small spatial and temporal scales over which these extreme events occur, and the complex conditions associated with the formation of such events, it is hard for climate models to resolve extreme events. As such, a literature review was conducted to explore the future of cold snaps and polar vortex events specifically across the service territory. Climate change is driving a general warming trend across the state of Colorado, leading to a decrease the number of days below 5°F by 2050. However, this does not preclude cold snaps from continuing to occur in the coming decades. There is uncertainty in the scientific community around how climate change is impacting extreme cold events at mid-latitudes. Yet, some evidence suggests that climate change could intensify certain cold extremes, such as those resulting from polar vortex events, all while decreasing the overall likelihood of cold snaps.[33] Given their complexity, extreme events were not included in the exposure scoring or vulnerability assessment.

VULNERABILITY ASSESSMENT

Vulnerability represents the potential for PSCo's assets and operations to be adversely impacted by projected climate hazards and the significance of associated outcomes for PSCo's systems, services, and customers. Asset vulnerability was scored to the following climate hazards: extreme heat, frozen precipitation, extreme wind, riverine flooding, and wildfire. The vulnerability assessment was based on the results of the exposure analysis and the Study Team's evaluation of each asset's sensitivity and criticality, see Figure 32.

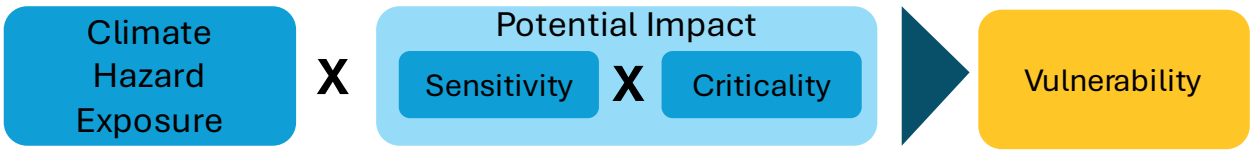


Figure 32. Vulnerability assessment approach.

SENSITIVITY

Sensitivity is defined as the degree to which PSCo's assets could be negatively affected by climate hazard exposures. It captures the extent to which an asset may degrade, fail to perform as designed, or require repair or replacement. "Failure" exists on a continuum, from failure to operate (e.g., de-energizing equipment as a preventive measure) to catastrophic failure (e.g., broken distribution poles and conductors).

Notably, specific climate hazards impact different individual assets and asset families in unique ways. For example, heat can lead to accelerated asset degradation and reduction of efficiency and capacity. Because different assets have unique vulnerabilities to specific climate hazards, assets were grouped under three main asset families: distribution, substation, and DERs.

Sensitivities are defined for multiple relevant natural hazard categories. The criteria for sensitivity ratings were defined as follows:

- (0) **Not Applicable** sensitivity is for assets that are not affected by a given climate hazard.
- (1) **Low** sensitivity refers to assets, operations, or systems facing minimal potential adverse impact from a given climate hazard.
- (2) **Moderate** sensitivity refers to assets, operations, or systems that may be adversely affected by a given climate hazard. Impacts are moderated by one or more factors, such as impacts being only likely at a very high threshold of exposure (e.g., very high temperature or water level) or being more likely to be chronic or controlled than sudden or acute (e.g., accelerated degradation rather than catastrophic failure).
- (3) **High** sensitivity refers to assets, operations, or systems that may be subject to increased likelihood of major and/or sudden failure in the event of hazard exposure, even at lower thresholds. The asset is bound to have limited existing tolerance for exposure to this hazard (e.g., pad-mount transformers and flooding).

Asset-specific sensitivity to each hazard is included in Appendix III.

CRITICALITY

Criticality was defined as the extent to which the failure of an asset to operate as designed would result in negative outcomes for PSCo's system, staff or the public. These ratings are completely independent from climate exposure and sensitivity; they reflect only the function importance of the asset in the system, not how likely an asset is to be exposed to climate hazard or its level of sensitivity to it. Criticality scores characterize the extent to which asset failure could result in:

- Interruption of energy delivery to customers
- Environmental and public or employee safety hazard
- Cascading failure of downstream assets

The criticality ratings were defined for each asset type as follows and the scores are listed by asset type in Table 8:

- (1) **Low**—failure of the asset results in minimal disruption to the ability to deliver energy or pose environmental or safety hazards (e.g., handful of customers losing power for up to several hours, localized failure).

- (2) **Moderate**—failure of the asset may result in minor safety risks to public or Company personnel and multiple sustained customer outages, but downstream failure is contained.
- (3) **High**—failure of the asset that may result in widespread or a very long duration outages, injuries or losses of life, or disable various downstream assets.

Table 8. Criticality scores for each asset.

Asset	Score	Justification
Distribution		
Distribution Poles	2	Pole failure is likely to result in localized circuit outage and may pose safety hazards.
Overhead Conductors	2	Conductor failure may result in localized outage for radial circuits. Downed conductors and overloading may pose safety hazards such as excessive sag and ignition of vegetation.
Overhead Transformers	2	Failure of an overhead transformer interrupts only a few customers, but if accompanied by rupture, it can endanger the public or result in ignition of vegetation.
Pad-mount Transformers*	2	Failure may result in outages ranging from a few residential customers or small commercial facilities to large industrial or commercial customers.
* Other pad-mounted equipment, like switch cabinets, were deprioritized due to their lower criticality compared to that of transformers.		
Substation		
Substation Transformers	3	Substations are typically designed for the loss of only one transformer. Transformers are complex devices with long lead times for replacement. The failure of a transformer can result in long-lasting outages. Multiple-day outages may be experienced even if access is viable to install temporary mobile transformers.
Circuit Breakers	2	Failure of feeder circuit breakers may result in line outage but customers can typically be restored by other means. Some circuit breakers contain oils and gases that could pose environmental hazards if released.
Protection and Control Devices	3	Failure of protection and control devices may require circuits to be taken out of service or result in loss of distribution system elements or pathways. The disruption may even extend to an entire substation.
Control Room/ Control House	3	Control rooms/control houses contain vital electronic equipment that assists with the monitoring and regulation of power. Failure of these systems may lead to grid instability and outages.
DERs		

Battery Storage	1	Failure of a battery energy storage system does not necessarily result in an outage because of available grid supply.
Solar Panels	1	Failure of a distributed solar panel should result in that resource disconnecting from the grid, thereby limiting the impact to the customer premise at which the resource is sited.

POTENTIAL IMPACT

Potential impact characterizes the negative outcomes to the system based on sensitivity level to given climate hazard and the criticality of the asset. Note that this score is independent of the climate hazard exposure score. The sensitivity and criticality scores were combined to derive potential impact, as shown in Table 9. Potential impact scores range from:

- **(0) Not Applicable**—when the asset is not sensitive to a given climate hazard, regardless of the asset's criticality score.
- **(1–2) Low**—for assets with low sensitivity or criticality. The impacts would be either minimal or quick to recover from.
- **(3–4) Moderate**—for assets with moderate sensitivity and up to high criticality or high sensitivity and low criticality. The impacts may result in considerable physical and operational challenges and sustained outages to recover from.
- **(6–9) High**—for assets with higher sensitivity and criticality. The loss of the assets would result in challenging physical and operational activities to recover from longer-term outages.

Table 9 . Potential Impact scoring rubric

Potential Impact		**Sensitivity Score**			
		0 (NA)	1 (Low)	2 (Moderate)	3 (High)
Criticality Score	1 (Low)	0	1	2	3
	2 (Moderate)	0	2	4	6
	3 (High)	0	3	6	9

Table 10 presents the resulting potential impact scores of each asset–hazard combination.

Table 10. Potential Impact scores of asset–hazard combinations.

Asset Family	Extreme Heat	Frozen Precipitation	Extreme Wind	Riverine Flooding	Wildfire
Distribution					
Poles	0	4	4	4	6
Overhead Conductors	4	6	4	2	4
Overhead Transformers	4	4	2	2	4
Pad-mount Transformers	4	0	0	6	6
Substations					
Substation Transformers/Regulators	6	6	3	6	3
Circuit Breakers	2	4	2	4	2
Protection & Control Devices	3	0	3	6	3
Control Room/Control House	3	0	3	9	3
Distributed Energy Resources					
Battery Storage	0	1	0	3	3
Solar Panels	0	2	3	2	3

The Study Team identified priority vulnerabilities upon exploration of the potential impact and climate exposure results at an asset-type level; these are listed in Table 11. Priority vulnerabilities are asset–hazard combinations that the Study Team analyzed further, at an individual-asset level, to determine individual vulnerability scores and are presented in the next section.

Table 11. List of priority vulnerabilities.

Asset Family	Extreme Heat	Frozen Precipitation	Extreme Wind	Riverine Flooding	Wildfire
Distribution					
Poles	-	✓	✓	✓	✓
Overhead Conductors	✓	✓	✓	-	✓
Overhead Transformers	✓	-	-	-	✓
Pad-mount Transformers	✓	-	-	✓	✓
Substations					
Substation Transformers/Regulators	✓	✓	-	✓	-
Circuit Breakers	-	✓	-	✓	-
Protection & Control Devices	-	-	-	✓	-
Control Room/ Control House	-	-	-	✓	-
Distributed Energy Resources					
Battery Storage	-	-	-	✓	✓
Solar Panels	-	✓	✓	✓	✓

INDIVIDUAL-ASSET VULNERABILITY

Vulnerability is defined by the IPCC as the degree to which a system is susceptible to, or unable to cope with, adverse effects of climate change. It is a function of the character, magnitude, and rate of climate variation to which a system is exposed (i.e., the exposure scores in this Study), its sensitivity, and its adaptive capacity (i.e., the potential impact scores in this Study).[34]

After potential impact scores were derived for each asset–hazard combination, the scores were multiplied by the exposure score for each climate hazard to derive asset vulnerability scores, as shown in Table 12, which range from:

- **(0) Not applicable**—the asset is either not exposed to a climate hazard or there is no likely impact due to not being sensitive to the hazard.
- **(1–10) Low**—the exposure to a climate hazard is minimal or within the allowable thresholds of asset design and operation. The asset may have a high exposure score, but the overall vulnerability is low due to either low asset criticality or sensitivity to the hazard.
- **(11–20) Medium**—the exposure to a climate hazard is near the allowable thresholds of asset design and operation. The asset may have a high exposure score, but the overall vulnerability is medium due to moderate asset criticality or sensitivity to the hazard.
- **(above 20) High**—the exposure to a climate hazard exceeds the allowable thresholds of asset design and operation. The asset overall vulnerability is high due to either high asset criticality or sensitivity to the hazard.

Table 12. Vulnerability scoring rubric.

Vulnerability		**Potential Impact Score**			
		0 (NA)	1-2 (Low)	3-4 (Moderate)	6-9 (High)
Exposure Score	0 (Not exposed)	0	0	0	0
	1 (Minimal exposure)	0	1-2	3-4	6-9
	2 (Minor exposure)	0	2-4	6-8	12-18
	3 (Moderate exposure)	0	3-6	9 - 12	18 - 27
	4 (Major exposure)	0	4-8	12-16	24-36
	5 (Maximal exposure)	0	5-10	15 - 20	30-45

The table below (Table 13) summarizes the climate hazards that result in medium and high vulnerabilities within each county of PSCo's service territory through 2080 under the SSP2-4.5 climate scenario.

Table 13. Counties with assets with medium or high vulnerability to climate hazards.

Extreme Heat	Wind	Riverine Flooding	Wildfire	Frozen Precipitation

County	Climate Hazard
Adams	
Alamosa	
Arapahoe	
Boulder and Broomfield	
Chaffee	
Clear Creek	
Conejos	
Costilla	
Denver	
Douglas	
Eagle	
Garfield and Gilpin	
Grand	
Gunnison	None
Jefferson	
Lake	
Larimer and Logan	
Mesa	
Morgan	
Park	
Pitkin	None
Rio Grande	
Saguache	
Summit	
Weld	

RESULTS

Vulnerabilities are presented by climate hazard (extreme heat, frozen precipitation, wind, riverine flooding, and wildfire) and asset type. The analysis was carried out at the individual-asset level. The number of distribution assets (representative of the distribution system as of December 2023) included in the analysis were:

- Poles (count): 600,395
- Overhead conductors (line miles): 2,882
- Overhead transformers (count): 84,159
- Pad-mount transformers[5] (count): 132,438
- Substations (count): 155
- Battery energy storage systems (facilities): 6
- Solar panels (locations): 107,074 [0.5% PSCo owned]

Vulnerability scores were normalized to a 1–10 scale for integration into the risk scoring framework explained in the next section. The vulnerability scores for all time horizons and climate scenarios included in the Study are in Appendix IV as percentages of assets that fall within a low, medium, or high classification. The highlights of the vulnerability scores are presented next. Violin plots were used to display the distribution of vulnerability scores, their shift through time horizons, and the contrast between the two climate scenarios. A guide for their interpretation is provided in Figure 33 below. In this scale, medium vulnerability starts at a value of 2.2 and high vulnerability at a value of 4.4.

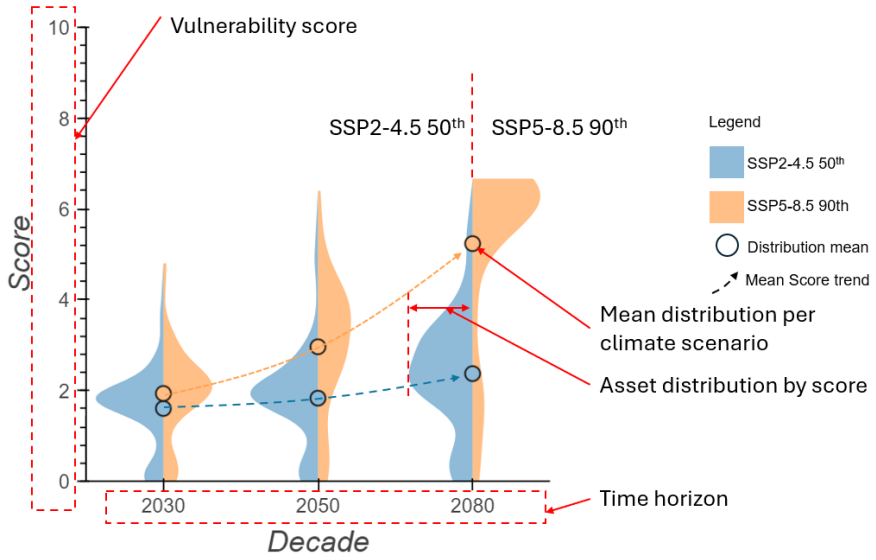


Figure 33. Guide for plot interpretation.

[5] Pad-mount transformers were used as a proxy for the vulnerability of underground conductors. The potential exposure of a pad-mount transformer to climate hazards would result in impacts to the underground distribution system.

Extreme Heat

The asset types that identified extreme heat as a priority vulnerability were overhead conductors, overhead transformers, pad-mount transformers, and substation transformers and regulators. By 2050, only substation transformers reach a high vulnerability score, 3% under SSP2-4.5 and 12% by SSP5-8.5. Five percent of overhead conductors, overhead transformers, and pad-mount transformers are projected to shift from low to medium vulnerability scores under the low emissions climate scenario. This percentage increases to 51%, 54%, and 48%, respectively, under the high emissions climate scenario. The score distribution is provided in Appendix IV and the vulnerability trend for overhead conductors and substation transformers is depicted in Figure 34. These results indicate that extreme heat projections result in limited short- to mid-term vulnerability that can be addressed through resilience measures identified in the next section of this report.

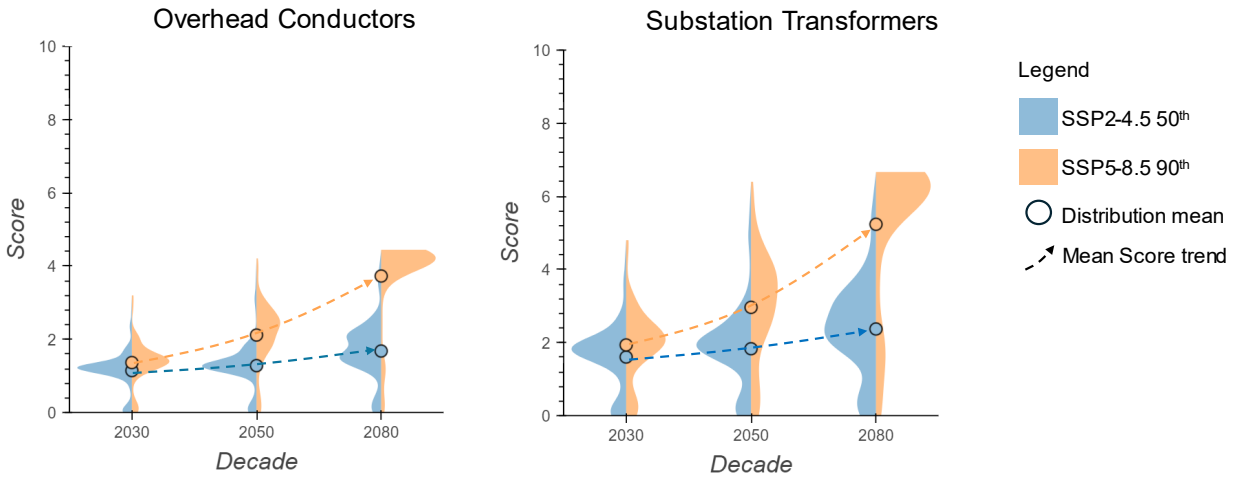


Figure 34. Vulnerability scores distribution for overhead conductors and substation transformers to extreme heat.

Frozen Precipitation

The asset types that identified frozen precipitation as a priority vulnerability were poles, overhead conductors, substation transformers and regulators, circuit breakers, and solar panels. By 2050, only substation transformers and overhead conductors reach a high vulnerability score—2% and 1% of these asset types under SSP5-8.5, respectively. All assets have low vulnerability to frozen precipitation under SSP2-4.5 in all time horizons. The score distribution is provided in Appendix IV and the vulnerability trend for overhead conductors, substation transformers, and solar panels is depicted in Figure 35. These results indicate that frozen precipitation projections trend toward more favorable conditions. The current design standards and asset management processes should continue to provide resilience to this climate hazard.

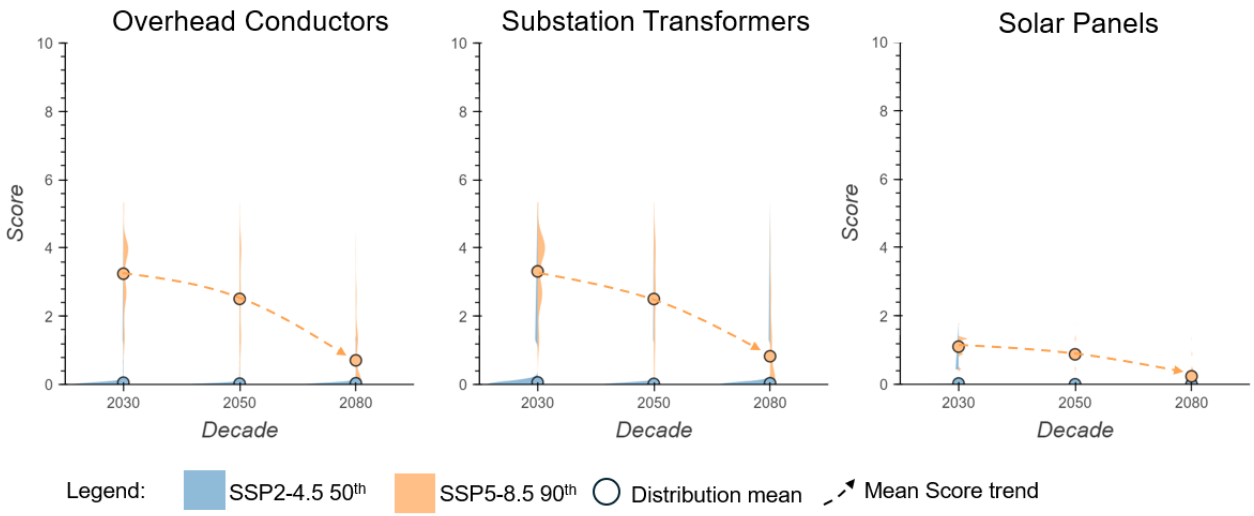


Figure 35. Vulnerability scores distribution for overhead conductors and substation transformers to frozen precipitation.

Wind

The asset types that identified extreme wind as a priority vulnerability were poles, overhead conductors, and solar panels. None of these assets reach high vulnerability scores throughout time horizons and climate scenarios. Nevertheless, the vulnerability score for all time horizons under SSP2-4.5 is medium for 38% of poles, 42% of overhead conductors, and 41% of solar panels. The score distribution is provided in Appendix IV. The vulnerability trend for this hazard is not projected to have significant variation from current-day conditions, as depicted in Figure 36 for overhead conductors and solar panels. Resilience measures for extreme wind are identified in the next section of this report.

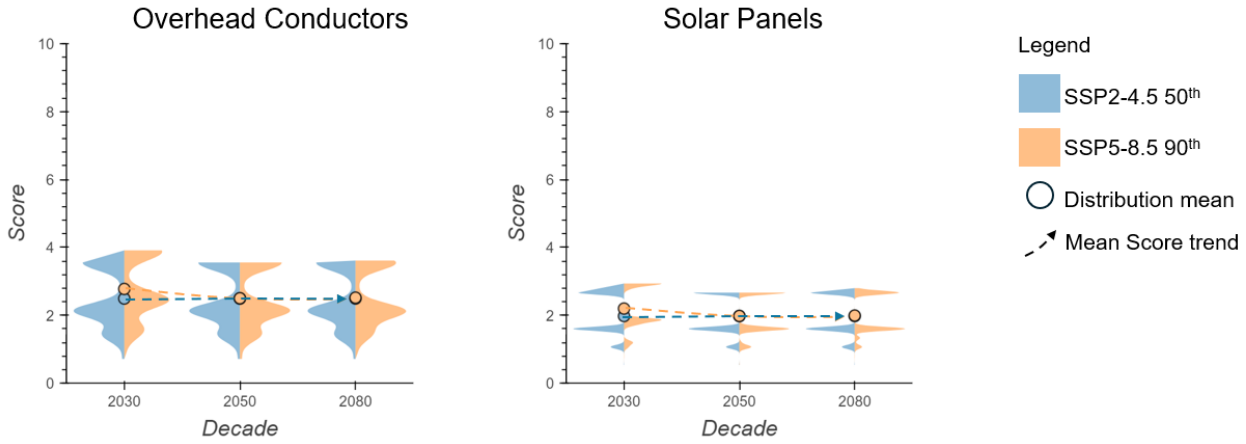


Figure 36. Vulnerability scores distribution for solar panels to wind.

Riverine Flooding

The asset types that identified riverine flooding as a priority vulnerability were poles, pad-mount transformers, substation components (transformers and regulators, circuit breakers, protection and control devices, and control room/house), battery energy storage systems (BESS), and solar panels. Solar panels and BESS were found to be outside of FEMA floodplains, so they have a low vulnerability score. Four substations (and associated components) are within a floodplain. These have either underground control rooms or the components are placed only 1 to 2 feet above grade. Their vulnerability is medium throughout time horizons and climate scenarios. All poles scored low vulnerability under SSP2-4.5 and 6% score medium vulnerability under SSP5-8.5. The score distribution is provided in Appendix IV and the vulnerability trend for substation transformers and solar panels is depicted in Figure 37. Riverine flooding is a localized current-day vulnerability that can be addressed through resilience measures identified in the next section of this report.

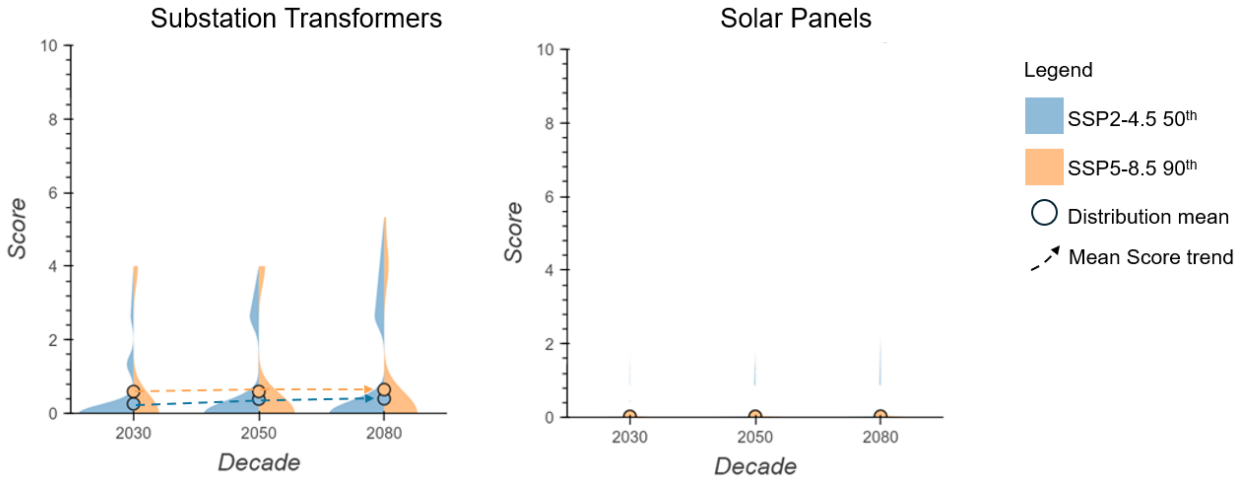


Figure 37. Vulnerability scores distribution for substation transformers and solar panels to riverine flooding.

Wildfire

The asset types that identified wildfire as a priority vulnerability were poles, overhead conductors, overhead transformers, pad-mount transformers, BESS, and solar panels. Only poles and pad-mount transformers reach a high vulnerability score under SSP5-8.5, with up to 4% of poles and 2% of pad-mount transformers. BESS have low vulnerability scores under all time horizons and climate scenarios. By 2050, one percent of solar panels reach a medium vulnerability score under SSP5-8.5. Six percent of poles have medium vulnerability to wildfire by 2050 under SSP2-4.5 and increase to 48% in SSP5-8.5. Overhead conductors increase from 3% to 7% under the same parameters, overhead transformers from 4% to 6%, and pad-mount transformers from 3% to 56%. The score distribution is provided in Appendix IV, and the vulnerability trend for overhead conductors and solar panels is depicted in Figure 38. Wildfire is a current-day (and future)

vulnerability that can be addressed through resilience measures identified in the next section of this report.

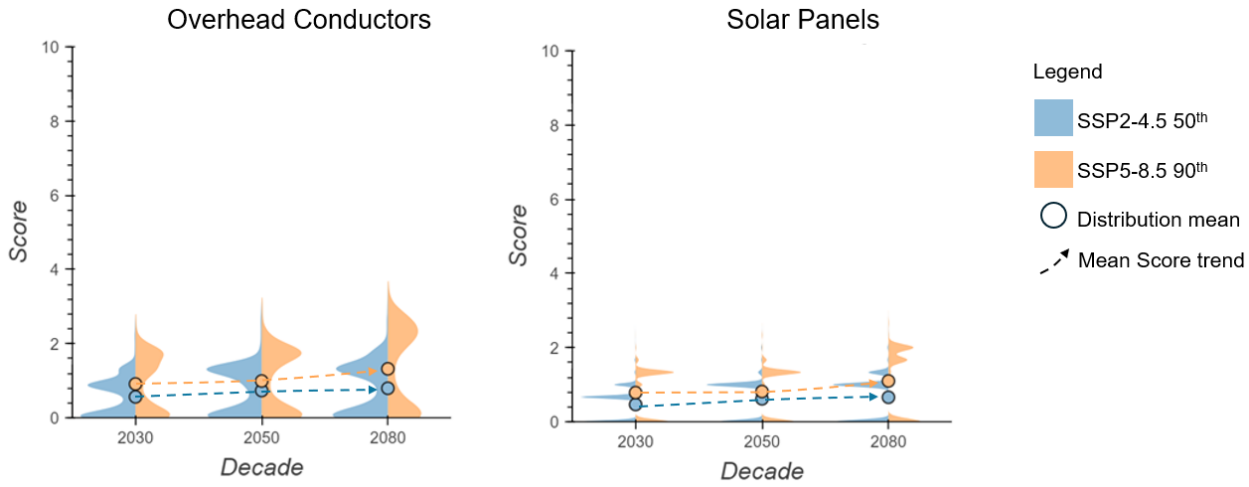


Figure 38. Vulnerability scores distribution for overhead conductors and solar panels to wildfire.

OPERATIONS AND PROCESSES VULNERABILITY

The Study Team evaluated the climate impacts on 10 distinct utility operations and processes. These included 1) load forecasting, 2) load relief planning, 3) portfolio planning and prioritization, 4) asset ratings, 5) flood design, 6) reliability assessment and planning, 7) work practices and safety, 8) emergency preparedness, 9) vegetation management, and 10) asset management.

Unlike the asset vulnerability assessment, the operations and processes vulnerability assessment is qualitative, relying on industry expertise to characterize the impacts of climate change on each of the operations and process areas. However, the analysis is informed by the quantitative exposure analysis. Table 14 presents a summary of the operations and processes vulnerabilities to climate change; a detailed analysis can be found in Appendix V.

Table 14. Summary of operations and processes vulnerable to climate change.

Operation/ Process	Relevant Hazards	Climate Vulnerability	Potential Mitigation Options
Load Forecasting	• Extreme Heat	Projected increases in temperature will lead to increases in demand. Current forecasting processes that rely on historical weather may inaccurately forecast peak demand and energy, resulting in possible overloads during summer periods.	• Incorporate climate projections into the load forecasting process. • Use of SCADA and advanced metering infrastructure (AMI) to gain insight into real-time system and asset loading.
Load Relief Planning	• Extreme Heat	Projected frequency and duration of heat waves, as well as projected increases in average and maximum temperatures will increase the frequency that PSCo assets are exposed to ambient temperatures above their ratings. In some instances, this may result in load shedding.	• Incorporate climate projections into load relief and capacity planning processes. • Use of SCADA and AMI to gain insight into real-time system and asset loading. • Maintaining accurate information on customer characteristics (i.e., critical customers, disadvantaged customers) to assist in load shedding and planning decisions.
Portfolio Planning and Prioritization	• Extreme Heat • Ice • Extreme Wind • Riverine Flooding • Wildfire	Many utility investment frameworks prioritize short-term risks and are not equipped to value climate impacts or risk reduction. Without modification of investment processes to account for long-term climate-informed risks, resilience measures may not receive necessary capital	• Incorporate climate risks into portfolio planning and prioritization processes. • Ensure resilience benefits are accurately represented in cost-benefit analyses.

Operation/ Process	Relevant Hazards	Climate Vulnerability	Potential Mitigation Options
		allocations, and the system can become ill equipped to confront the risks posed by climate change. Climate hazards may also increase short-term spending to repair and replace assets.	
Asset Ratings	• Extreme Heat • Extreme Wind	Increased temperatures are expected to cause increases in demand and decreases in capacity potentially pushing assets beyond their temperature ratings, resulting in potential damage, failure, or load shedding. Wind ratings may also be exceeded as wind speeds are expected to increase.	• Incorporate climate projections into asset rating process.
Flood Design	• Riverine Flooding	Current flood standards that are in place may be exceeded and assets that currently are not designed to withstand flooding may need to be retrofitted to include flood protection measures.	• Incorporate flood projections that consider both the historical floodplain and future precipitation projections when creating flood siting and design standards. • Review existing and future assets to assess their vulnerability to flooding.
Reliability Assessment and Planning	• Extreme Heat • Ice	Climate change is projected to increase the frequency and severity of extreme weather	• Investment in adaptation measures that address specific

Operation/ Process	Relevant Hazards	Climate Vulnerability	Potential Mitigation Options
	• Extreme Wind • Riverine Flooding • Wildfire	events resulting in outages and reliability impacts. Absent resilience measures, reliability could fall beneath performance targets.	resilience measures (i.e., flood mitigation). • Investment in adaptation measures that increase redundancies and overall system resilience (i.e., N-1/N-2 substation design, looped feeders, etc.)
Work Practices and Safety	• Extreme Heat • Ice • Extreme Wind • Riverine Flooding • Wildfire	Projected increasingly frequent and severe weather events caused by climate change are likely to cause unsafe conditions for utility workers, especially those in the field. Current work practices and safety standards often address conditions based on historical weather events and past safety failures and may fail to account for the level of intensity or types of hazards that climate change may cause.	• Evaluate new potential worst-case scenarios caused by climate change-related extreme weather events as well as potential risks that may be present on a day-to-day basis and update worker safety standards as needed. • Routinely revisit standards based on on-the-ground conditions and updated projections.
Emergency Preparedness, Response, and Restoration	• Extreme Heat • Ice • Extreme Wind • Riverine Flooding • Wildfire	The projected increasing frequency and magnitude of extreme weather events may strain current emergency response resources and result in increased costs for the Company to repair and replace damaged assets and compensate staff for overtime hours. Large extreme events may	• Ensure appropriate funding and resources for projected increased threats posed by climate change. • Use of advanced technologies, such as early warning systems, can help utilities more efficiently prepare and respond to

Operation/ Process	Relevant Hazards	Climate Vulnerability	Potential Mitigation Options
		also impact other utilities and limit the amount of mutual aid available to assist in restoration efforts. Additionally, more frequent emergency activations may become disruptive to blue-sky staff duties.	emergency situations.
Vegetation Management	• Extreme Heat • Ice • Extreme Wind • Wildfire	Projected average temperature increases may result in changes in growing cycles and the spread of invasive species, both of which can increase the likelihood of tree contact with overhead lines. Increases in extreme wind can heighten the likelihood of vegetation contact, especially when compounded with oversaturated soil caused by extreme precipitation. Lastly, as wildfire risk increases, vegetation management will become increasingly important to prevent spread and ignition.	• Utilize condition-based vegetation management instead of time-based cycles. • Procure additional easements to widen rights-of-way. • Expand clearances. • Adopt new technologies to identify clearance violations. • Install additional aerial cable or tree wire.
Asset Management	• Extreme Heat • Ice • Extreme Wind • Riverine Flooding • Wildfire	Extreme heat, ice, extreme wind, flooding, and wildfires are all projected to increase in the service territory and pose significant challenges for a wide array of assets, which may result in increased rates of failure, repair, and replacement.	• Implement a comprehensive failure database to track asset failure and inform asset management decisions. • Develop health indices to closely

Operation/ Process	Relevant Hazards	Climate Vulnerability	Potential Mitigation Options
		Supply chains may also become stressed due to climate change, which may pose challenges for maintaining adequate replacement assets and spare parts.	monitor asset condition. • Utilize storm hardening and other adaptation measures to reduce failure rates and prevent damage from climate hazards. • Remove poorly performing assets through end-of-life replacement programs. • Utilize remote condition assessment technologies to monitor temperature-sensitive assets and potential impacts.

RISK SCORING

As a next step to the vulnerability assessment process, risk scores were established at the asset-specific level to inform the priority of intervention. Under this framework, risk is the interaction between vulnerability and consequence, see Figure 39.

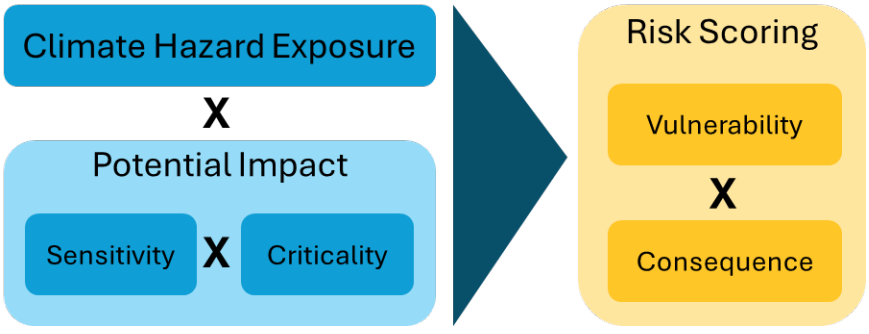


Figure 39. Risk scoring process diagram

In the context of resiliency, consequence can be defined in different ways. The IPCC considers consequence, or impact, to be the "realized risks on natural and human systems." Consequence encompasses the interactions of climate-related hazards,

exposure, and vulnerability and offers insight into how these interactions affect social, cultural, and economic sectors.[35]

In the context of this assessment, consequence is focused on the outcomes to customers and communities, defined as the adverse impacts they may experience due to an outage. Three metrics were used to define and characterize customer and community impacts related to power outages, see Figure 40.

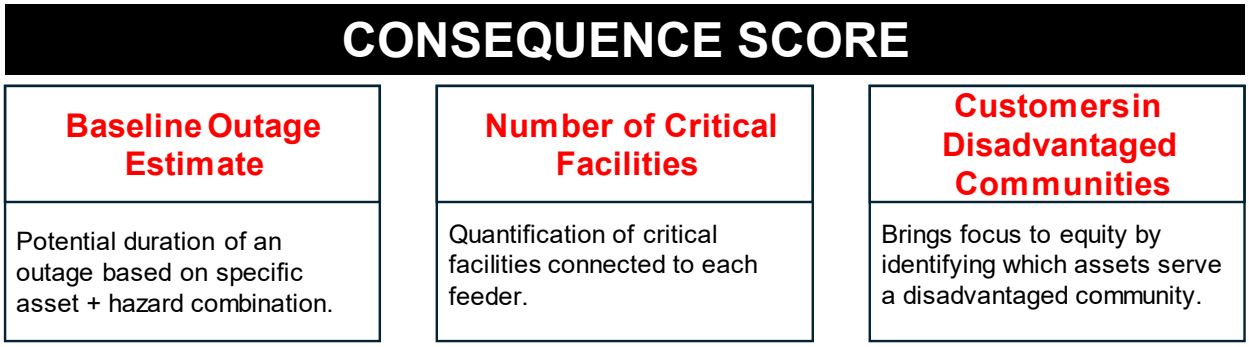


Figure 40. Consequence scoring metrics.

BASELINE OUTAGE ESTIMATE

The baseline outage estimate captures the magnitude of the potential outage for a specific asset type when exposed to a particular hazard, thereby indicating the relative severity of outage across various asset-hazard combinations. The baseline outage estimate scoring is based on a scale ranging from 1 to 5, as follows:

- 1 — outage lasting minutes
- 2 — outage lasting hours
- 3 — outage lasting days
- 4 — outage lasting weeks
- 5 — outage lasting months

The Study Team calculated the outage estimate for each discrete asset (i.e., adjusted outage estimate) using the baseline outage scores and the following formula:

$$AOE = (BOE) * \left(1 + \frac{Vulnerability\ Score}{Max.Vulnerability\ Score}\right)$$

$where,$
$AOE = Adjusted\ Outage\ Estimate$
$BOE = Baseline\ Outage\ Estimate$
$Max.Vulnerability\ Score = 45\ (see\ \text{Table 12})$

To complete the calculations, the adjusted outage estimate score was normalized and then converted into weighted scores. To normalize the adjusted outage estimate scores, the following formula was used:

$$Normalized\ Score = \left(\frac{Raw\ Score}{45}\right) * 10$$

See Table 15 for example calculations.

NUMBER OF CRITICAL FACILITIES

PSCo maintains a list of critical customers that includes major hospitals, airports, water and wastewater treatment facilities, public safety facilities, etc. The list of critical customers is being updated under a different effort; therefore, the results presented in this section illustrate the methodology to include critical facilities and not for decision making. These critical customers are also community lifelines, which enables the continuous operation of critical government and business functions and are essential to human health, safety, or economic security[36]. The count of critical facilities was tallied by feeder level and cascaded to the individual assets associated with each feeder. This method allows differentiation and prioritization of assets that may have the same vulnerability score but serve more critical customers than others. The scores for the number of critical facilities were normalized on a 0 to 10 scale, using the same normalization formula as above. Similar to the outage estimate scores, the normalized critical facilities scores were also weighted.

CUSTOMERS IN DISADVANTAGED COMMUNITIES

PSCo identified assets that serve disadvantaged communities (DACs), acknowledging the role that the Company has in the resilience and equitable distribution of resources in the communities it serves. In accordance with the Colorado EnviroScreen definition, DACs were defined as “communities where multiple factors, including socioeconomic stressors, vulnerable populations, disproportionate environmental burdens, vulnerability to environmental degradation or climate change, and lack of public participation may act cumulatively to affect health and the environment and may contribute to persistent environmental health disparities”. A geospatial analysis was carried out to identify assets that serve disadvantaged communities, as depicted in Figure 41. Based on this analysis, each discrete asset was assigned a binary score of 0 or 1, where 1 indicates a feeder in a DAC, and 0 means the feeder does not cross through a DAC. Once again, the scores were normalized on a 0 to 10 scale and were also weighted.

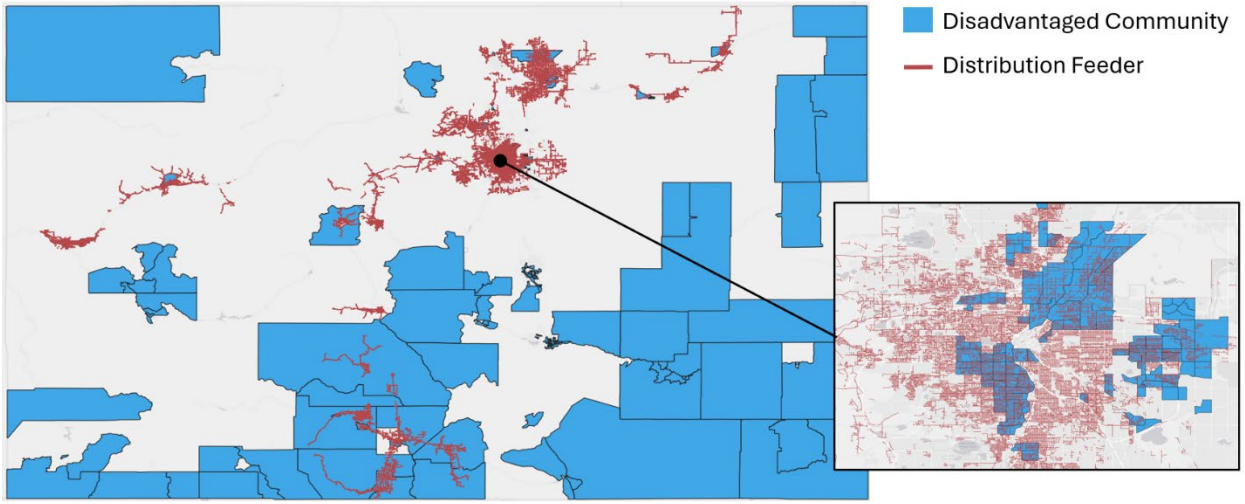


Figure 41. Disadvantaged communities in PSCo's service territory

The normalized and weighted scores for outage estimate, critical facilities, and disadvantaged communities were then summed up to arrive at a consequence score for each discrete asset. Each of these components that make up the consequence score is weighted equally. Table 15 below shows the results of these calculations for transformer assets that are exposed to extreme heat at selected substations.

Table 15. Example consequence scores for transformers assets and exposure to extreme heat.

Substation	Outage Estimate Scores		Critical Facilities Scores		Disadvantaged Community Scores		Consequence
	Normalize (out of 10)	Weight (out of 3.33)	Normalize (out of 10)	Weight (out of 3.3)	Normalize (out of 10)	Weight (out of 3.3)	Total Score (out of 10)
G.J.	2.5	0.8	2	0.7	10	3.3	4.8
A.	2.4	0.8	0	0	10	3.3	4.1
S.	2.4	0.8	0	0	10	3.3	4.1
D.	2.3	0.8	0	0	10	3.3	4.1
R.	2.1	0.7	0	0	10	3.3	4.0
G.	2.4	0.8	2	0.7	0	0	1.5
A.	2.4	0.8	2	0.7	0	0	1.5
Av.	2.4	0.8	0	0	0	0	0.8
L.	2.4	0.8	0	0	0	0	0.8
S.	2.1	0.7	0	0	0	0	0.7

The consequence scores at the individual-asset level are independent of climate scenarios, time horizons, and climate hazards of interest. They only change if the metrics of consequence change (e.g., additional critical facilities). The exposure score in the vulnerability component of the risk score is what captures the effects of climate change. Table 16 illustrates the risk scores for heat and flooding of these substation transformers, for the 2050 SSP2-4.5 climate scenario. Additional risk score results are included in Appendix VI.

Table 16. Heat and Flood risk scores for substation transformers.

		Heat		Flood	
Substation	**Consequence Score (out of 10)**	**Vulnerability Score (out of 10)**	**Risk Score (out of 100)**	**Vulnerability Score (out of 10)**	**Risk Score (out of 100)**
G.J.	4.8	2.7	12.9	0	0
A.	4.1	2.1	8.8	0	0
S.	4.1	1.9	7.7	0	0
D.	4.1	1.6	6.6	0	0
R.	4.0	0.3	1.1	0	0
G.	1.5	2.1	3.2	0	0
A.	1.5	1.9	2.7	2.7	6.3
Av.	0.8	1.9	1.5	0	0
L.	0.8	1.9	1.5	0	0
S.	0.7	0.3	0.2	0	0

The qualitative risk thresholds established below can be interpreted as the result of one or more of the following conditions:

- **Low (0 to 20)**: the climate hazard conditions in comparison to the baseline are not changing drastically; the asset is not sensitive to the hazard; the consequence associated with the asset is contained.

- **Medium (over 20 to 50)**: the climate hazard conditions in comparison to the baseline are changing toward less favorable conditions; the asset is sensitive to the hazard; critical facilities and customers that may be in DACs may be impacted.

- **High (over 50)**: the climate hazard conditions in comparison to the baseline are changing toward extreme weather conditions; the asset is very sensitive to the hazard; many critical facilities and customers that may be in DACs may be impacted.

Risk scores should not be interpreted as a direct probability of assets being exposed to or being affected by climate hazards. Instead, they provide a framework to prioritize capital investment in addition to current decision-making parameters.

The risk scores also highlight the need for incremental scope on capital projects for climate adaptation. The risk score includes vulnerability, which in turn is based on the level of exposure to a hazard and the asset's sensitivity to it. Therefore, high risk to a climate hazard, such as extreme heat or flooding, would indicate that the project needs to include projected ambient temperatures instead of historical or floodproofing measures, respectively. The following section illustrates how risk scores may be used to prioritize and inform the scope of a capital project.

PROJECT PRIORITIZATION AND ADAPTATION

Equipped with risk scores at the asset level, PSCo can now integrate these scores into existing project prioritization frameworks. Currently, capital projects are decided based on the analysis of growth, electrification, reliability scores at the feeder level, equipment vintage, health and condition inspections, equipment failure, and other parameters used to identify projects that maintain safe and reliable service.

Moving forward, the calculated resilience scores can be added into the project prioritization framework to increase the degree to which prioritization is climate-resilience informed. The inclusion of risk scores to prioritize projects results in forward-looking decision making by considering projected changes in climate conditions, an equitable distribution of investment by identifying projects within DACs, and community-resilience focus by identifying projects that serve community lifelines. To illustrate this, the Study Team took a sample of 45 substation transformers that have been identified for replacement as part of the maintenance cycle and added their respective risk scores, shown in Table 17.

Table 17. Heat and Flood risk scores of substations transformers identified for replacement due to condition.

Substation Transformer	Heat Risk Score (out of 100)	Flood Risk Score (out of 100)
Bt.	8.3	6.9
B.C.	0	0
B.T.	7.7	0
C.	13.9	22.3
Ch.	1.0	0
E.	12.0	19.6
Ed.	14.0	0
F.	0.4	0
G.	3.2	0
M.	11.7	0
Me.	1.2	0
R.	7.7	0

The substations associated with this project sample, 49% serve a DAC, 40% serve at least one critical facility, and 100% have low risk scores for heat by 2050 under SSP2-4.5. These results indicate that no adaptation to extreme heat is required when designing or purchasing the new transformers. The projects associated with the California and East substations should be evaluated for potential flood risk.

The Study Team also reviewed a sample of 124 capacity-upgrade projects resulting from PSCo's latest load forecast analysis in 2024. Table 18 below displays the heat and flood risk scores of the 56 substations associated with the capacity-upgrade projects.

Table 18. Heat and Flood risk scores of substations associated with capacity upgrade projects.

Substation Transformer	Heat Risk Score (out of 100)	Flood Risk Score (out of 100)
Al.	2.7	6.3
An.	1.1	0.0
Ar.	7.7	0.0
Av.	1.5	0.0
Be.	2.2	0.0
Br.	3.1	5.4
Bu.	10.8	0.0
C.H.	6.4	0.0
Ch.	1.0	0.0
Cl.	3.3	7.2
C.L.	2.2	0.0
Da.	6.6	0.0
D.C.	0.3	0.0
D.T.	13.8	0.0
De.	11.4	18.7
Ea.	12.0	19.6
El.	0.0	0.0
F.H.	12.0	0.0
Gi.	0.2	0.0
Gl.	0.0	17.8
Gr.	12.9	0.0
Ha.	18.2	0.0
Hav.	8.3	0.0
Je.	22.0	0.0
Jo.	0.0	0.0
Ke.	2.1	0.0
La.	7.4	11.6
Lak.	9.6	0.0
Las.	1.7	0.0
Le.	7.7	0.0
Li.	5.5	0.0
Lo.	0.0	0.0
Lou.	1.5	0.0
Ma.	0.8	0.0
M.H.	3.1	6.3
Mo.	6.6	0.0
Mon.	0.0	0.0
Monr.	8.3	0.0
M.G.	3.1	4.5
P.	2.7	6.3
Q.	1.5	4.5
R.	1.2	0.0
Ri.	0.0	0.0
Riv.	11.4	0.0
S.	1.1	0.0
Se.	0.6	0.0
Si.	0.2	0.0
S.R.	2.1	0.0

Substation Transformer	Heat Risk Score (out of 100)	Flood Risk Score (out of 100)
S.L.	0.4	0.0
S.	7.7	0.0
S.R.	4.9	6.3
T.C.	3.1	0.0
T.	8.3	0.0
U.R.	8.3	0.0
V.	2.2	0.0
W.	6.3	0.0

From these substations, 42% serve a DAC, 63% serve at least one critical facility, and 100% have low risk scores for flooding by 2050 under SSP2-4.5. Aside from one substation, which has a medium risk score of 22, all other substations have low risk scores for extreme heat by 2050 under SSP2-4.5. These results indicate that no adaptation to inland flooding is required when designing the capacity-upgrade projects. The projects associated with the one substation with medio risk score should be screened under projected temperatures when designing the capacity-upgrade projects to verify adequacy for future conditions.

When the need for adaptation is identified, the resilience framework described in the next section can be leveraged to understand potential measures.

POTENTIAL RESILIENCE MEASURES

Building on the vulnerability assessment, this section identifies potential resilience measures to mitigate the most impactful asset–hazard combinations through a resilience framework that integrates physical and operational intervention in four key objectives.

RESILIENCE FRAMEWORK

The overarching framework for enhancing resilience across PSCo's system is shown in Figure 42. It centers on four key objectives (or dimensions) and corresponding strategies that seek to:

1. **Strengthen** assets and operations to **withstand** the adverse impacts of a climate hazard event.
2. Increase the system's ability to **anticipate** when a climate hazard event may occur and **absorb** its effects.
3. Bolster the system's ability to quickly **respond** and **recover** in the aftermath of a climate hazard event.
4. **Advance** and **adapt** the system to address a continuously changing threat landscape and perpetually improve resilience.

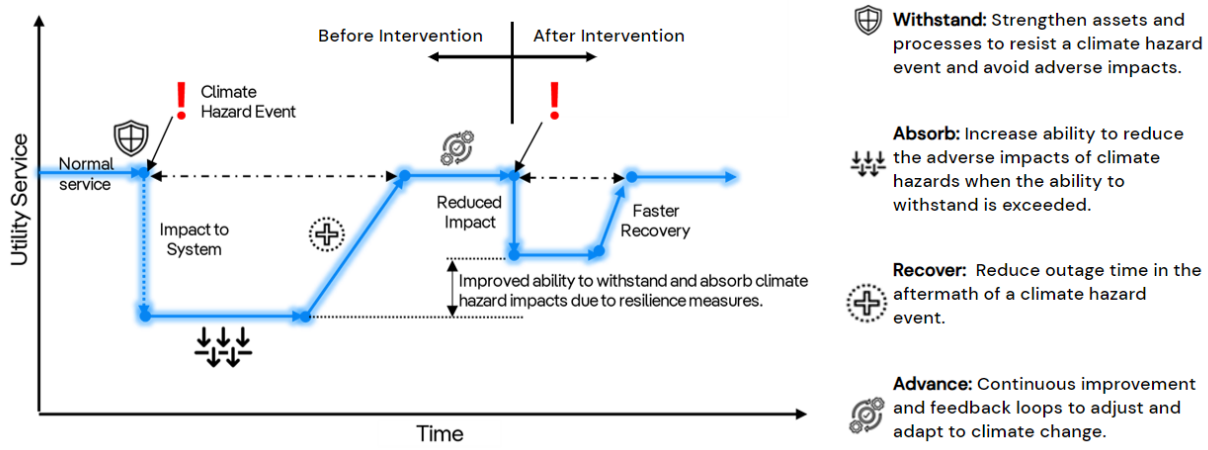


Figure 42 - Dimensions of the resilience framework.

The framework's holistic and structured approach to building resilience makes it a robust model for enhancing PSCo's resilience capabilities in the face of changing climate and increased frequency and intensity of severe weather events.

RESILIENCE MEASURES

The measures outlined below were developed through a collaborative process that included two workshops and involved many SMEs. Their collective expertise and experience have informed and shaped these measures, ensuring they were tailored to specific asset–hazard vulnerabilities, while also aligned with considerations of cost, feasibility, and other key factors.

The measures are grouped by hazard and identify applicable asset type, resilience measure type (physical or operational), and relevant resilience dimensions (i.e., withstand, absorb, recover, and adapt).

Wind and Frozen Precipitation

Across the PSCo service territory, distribution system vulnerabilities related to wind and frozen precipitation events include pole damage or failure, damage to overhead conductors, and conductor galloping, which may lead to flashovers or mechanical failures. For substation equipment, such as transformers, regulators, and circuit breakers, icing could cause flashovers on transmission level bushings and insulators, particularly if there is contamination present. Additionally, wind and hail could damage photovoltaic installations, while ice accumulation could lead to reduced solar output. Table 19 lists current and potential future adaptation measures.

Table 19. Resilience measures to enhance resilience to wind and frozen precipitation.

Resilience Measure	Asset Type	Resilience Measure Type	Resilience Dimension
Targeted undergrounding*	Distribution Poles, Conductors (Overhead)	Physical	
Targeted “ground to sky” trimming program*	Distribution Poles, Conductors (Overhead)	Operational	
Change design standards (shorten spans, dead-ending lengths)*	Distribution Poles, Conductors (Overhead)	Operational	
Reinforce poles*	Distribution Poles	Physical	
Replace pole with stronger pole*	Distribution Poles	Physical	
Review and update capital investment evaluation and prioritization methodology	All Assets	Operational	
Implement sectionalizing to minimize impact of damaged sections*	Conductors (Overhead)	Physical	
Reduce customer count per feeder	Conductors (Overhead and Underground)	Operational	
Implement redundancy with circuit ties; where ties are available, confirm there is sufficient capacity to support temporary additional load	Conductors (Overhead)	Operational	
Deploy anti-icing technologies such as semi-conductive or hydro-phobic coatings	Substation Transformers/Regulators, Substation Circuit Breakers	Physical	
Stronger module system design (e.g., new modules with at least 3.2 mm front tempered glass and a support bar)	Solar Panels	Physical	
For existing PV, change to higher tilt angles (less horizontal) to minimize hail impact	Solar Panels	Physical	
Request proof of passing hail test from manufacturer	Solar Panels	Operational	
Upgrade structural support standards	Solar Panels	Operational	
Microgrids*	All Distribution and Substation Assets	Physical	
Legend:  Withstand,  Absorb,  Recover,  Advance			
* Denotes initiatives that are already in progress, including those preliminary or in pilot stages).			

Riverine Flooding

PSCo's distribution poles and pad-mounted transformers were found to be highly vulnerable to riverine flooding events, including potential compromised structural integrity in poles and damage to transformers. Flooding could also cause damage or failure to substation transformer components, such as control cabinet, radiators, fans, pumps, external wiring connections, and the other accessories. Additional equipment susceptible to flooding includes circuit breakers installed at grade level, protection and control devices, as well as control rooms and houses at or below grade level. Similar risks were identified for battery storage and auxiliary equipment of photovoltaic installations. To address these vulnerabilities, PSCo has identified the following adaptation measures:

Table 20. Resilience measures to enhance resilience to riverine flooding.

Resilience Measure	Asset Type	Resilience Measure Type	Resilience Dimension
Consider flood exposure in capital planning (for asset locations)	Distribution Poles	Operational	
Use pole wrap in wet/flood prone areas	Distribution Poles	Physical	
Raise vulnerable equipment when feasible	Distribution Transformers (Pad-Mounted), Substation Transformers/Regulators, Substation Circuit Breakers, Substation Protection and Control, Substation Control Room/Control House, Solar PV	Physical	
Develop flood-safe de-energization and recovery protocols*	Transformers (Pad-Mounted)	Operational	
Implement dry-floodproofing (e.g., flood walls/flood gates, temporary inflatable barriers)	Substation Transformers/Regulators, Substation Circuit Breakers, Substation Protection and Control, Substation Control Room/Control House	Physical	
Enable load transfer to an alternate substation as an interim measure	Substation Transformers/Regulators, Substation Circuit Breakers, Substation Protection and Control, Substation Control Room/Control House	Operational	
Relocate substations within floodplains	Substation Transformers/Regulators, Substation Circuit Breakers, Substation Protection and Control, Substation Control Room/Control House	Physical	
Microgrids*	All Distribution and Substation Assets	Physical	
Legend:  Withstand,  Absorb,  Recover,  Advance			

Resilience Measure	Asset Type	Resilience Measure Type	Resilience Dimension
* Denotes initiatives that are already in progress, including those preliminary or in pilot stages).			

Extreme Heat

Extreme heat was found to pose risks to both overhead conductors and transformers (overhead and pad-mounted). For conductors, extreme heat could accelerate aging, heighten the risk of equipment damage, and exacerbate "line sag," which in turn makes contact with trees or other conductors more likely. Similarly, extreme heat could reduce transformer capacity, accelerate aging, and elevate the risk of failure. These risks were also noted in substation transformers and regulators. To address these vulnerabilities, PSCo has identified the following adaptation measures:

Table 21. Adaptation measures to enhance resilience to extreme heat.

Resilience Measure	Asset Type	Resilience Measure Type	Resilience Dimension
Implement energy efficiency programs	Conductors (Overhead), Transformers (Overhead), Transformers (Pad-Mounted), Substation Transformers/Regulators	Operational	
Implement targeted demand response programs	Conductors (Overhead), Transformers (Overhead), Transformers (Pad-Mounted), Substation Transformers/Regulators	Operational	
Upgrade conductor size	Conductors (Overhead)	Physical	
Implement non-wires alternatives to reduce demand	Conductors (Overhead), Substation Transformers/Regulators	Physical	
Targeted vegetation management	Conductors (Overhead)	Operational	
Increase ambient temperature design standards	Transformers (Overhead), Transformers (Pad-Mounted)	Operational	
Use of AMI data to analyze load conditions, monitor transformer performance, and implement predictive/enhanced maintenance	Transformers (Overhead), Transformers (Pad-Mounted)	Operational	
Replace existing units with higher capacity units	Transformers (Overhead), Substation Transformers/Regulators	Physical	
Install additional transformer or substations to reduce loading	Substation Transformers/Regulators	Physical	
Upgrade cooling system to increase capacity**	Substation Transformers/Regulators	Physical	
Expand mobile substation equipment fleet (mobile switchgear, mobile transformers, etc.)	Substation Transformers/Regulators	Physical	

Resilience Measure	Asset Type	Resilience Measure Type	Resilience Dimension
Enable load transfer to an alternate substation as an interim measure	Substation Transformers/Regulators	Operational	
Microgrids*	All Distribution and Substation Assets	Physical	
Legend: Withstand, Absorb, Recover, Advance			
* Denotes initiatives that are already in progress, including those preliminary or in pilot stages).			
** The capacity of existing transformers can be upgraded by 10 to 20 percent by a combination of re-analyzing thermal performance using more advanced methods and upgrading the cooling system by adding or replacing radiators, fans, pumps, or coolers.			

Wildfires

Distribution poles, conductors, and transformers (overhead and pad-mounted) were identified as highly vulnerable to wildfires. This includes damages to poles and pad-mounted transformers, while conductors and pole-mounted transformers could potentially cause wildfires due to an elevated risk of flashover. Additionally, wildfires pose a significant risk of damage to battery storage systems and photovoltaic installations. To address these vulnerabilities, PSCo has identified the following adaptation measures, which align, expand upon or complement the strategies identified in PSCO's wildfire mitigation plan:

Table 22. Adaptation measures to enhance resilience to wildfires.

Resilience Measure	Asset Type	Resilience Measure Type	Resilience Dimension
Fire retardant coating on poles	Distribution Poles	Physical	
Targeted undergrounding*	Distribution Poles, Conductors (Overhead), Transformers (Overhead)	Physical	
Increased clearances in vegetation management	Conductors (Overhead), Transformers (Overhead), Battery Storage, Solar PV	Operational	
Targeted sectionalization*	Conductors (Overhead)	Physical	
Public Safety Power Shutoffs (PSPS)*	Conductors (Overhead), Transformers (Overhead)	Operational	
Install firewalls in targeted locations*	Transformers (Pad-Mounted), Battery Storage	Physical	
Microgrids* and other customer resilience measures	All Distribution and Substation Assets	Physical	
Legend: Withstand, Absorb, Recover, Advance			
* Denotes initiatives that are already in progress, including those preliminary or in pilot stages.			

CONCLUSION AND NEXT STEPS

PSCo is dedicated to delivering safe and reliable service to customers, even amidst the challenges of a changing climate. This Vulnerability Study aimed to identify key climate hazards and priority climate vulnerabilities for specific assets across PSCo's service territory. This Study intends to build upon existing resilience work across PSCo and provide a foundation for effective prioritization of future resilience investments.

Based on the downscaled climate projections developed for this Study and consultation with the Company's subject matter experts, this Study identified five key climate hazards particularly relevant to PSCo's assets: 1) extreme heat, 2) extreme wind, 3) riverine flooding, 4) frozen precipitation, and 4) wildfires. The Study evaluated distribution, substation, and DER assets to assess their vulnerability and risk to each key climate hazard.

The vulnerability assessment and resilience measures presented in this Study were developed based on key climate science findings specific to different climate hazards across the PSCo service territory. The climate science component of this Study analyzed how different climate hazards are projected to change across the PSCo service territory under different time horizons and socioeconomic pathways. The key findings for SSP2-4.5 by 2050 are:

- The number of days with maximum temperatures above 95°F and above 104°F are projected to increase to 70 and 11 days respectively, relative to baselines of 35 and 1 days per year.
- The number of 2-day heat wave events is projected to be ~4 heat wave events, relative to a baseline of less than 1.
- Frozen precipitation is projected to remain variable across the service territory with decreases likely under both climate scenarios.
- Wind is not projected to change significantly and will remain variable across the PSCo service territory.
- More variable and intense extreme precipitation is projected to drive increases in inland flooding, particularly in areas around FEMA 100- and 500-year flood plains due to projected increases in annual maximum 5-day precipitation of up to 8.6% relative to a baseline range of 1 to 4.2 inches.
- The number of high fire danger days is projected to increase by up to 13 days.

The projections for each of these hazards was used to inform the vulnerability assessment. This Study calculated vulnerability scores at the individual-asset level through a quantitative analysis of asset exposure, sensitivity, and criticality. It is focused

on current physical assets, significant changes in assets will change the overall results. The findings by 2050, under SSP2-4.5 are listed next:

- 3% of substation transformers are projected to have high vulnerability scores to extreme heat driven by an increased exposure to higher ambient temperatures. No other assets are projected to reach high vulnerability scores to any of the other identified climate hazards.

- 5% of distribution assets, (including overhead conductors, overhead transformers and pad mount transformers), are projected to have medium vulnerability to extreme heat. Similarly, 6% of poles, 3% of overhead conductors, 4% of overhead transformers, and 3% of pad mount transformers are projected to have medium vulnerability to wildfires.

- 38% of distribution poles, 42% of overhead conductors, and 41% of solar PV are projected to have medium vulnerability to wind.

- 3% of pad mount transformers and 14% of all substation assets (including transformers, protection & control devices, and control rooms) are projected to have medium vulnerability to flooding.

- No assets are projected to have medium or high vulnerability to frozen precipitation.

Building on the asset vulnerability analysis, the Study also arrived at an individual-asset level risk score, which was developed by combining vulnerability with three consequence metrics: 1) number of critical facilities served, 2) whether disadvantaged communities are served by the asset, 3) estimated outage time caused by asset failure. These consequence metrics are centered in the impact to the community upon an outage event. The resulting risk score could then be used to inform priority of investment, in conjunction with other existing project prioritization considerations, such as maintenance and capacity requirements. This framework was demonstrated by reviewing the risk score of extreme heat and flooding of projects that were selected for capacity upgrades and reliability upgrades. None of the screened projects had a high risk score, indicating that no additional scope to adapt to these hazards is required.

In addition to asset vulnerabilities, this study also evaluated potential vulnerabilities of 10 distinct utility operations and processes: 1) load forecasting, 2) load relief planning, 3) portfolio planning and prioritization, 4) asset ratings, 5) flood design, 6) reliability assessment and planning, 7) work practices and safety, 8) emergency preparedness, 9) vegetation management, and 10) asset management.

Extreme heat poses the most vulnerabilities to PSCo’s operations and processes. Increasing ambient temperatures may lead to capacity overload on assets due to a combination of capacity reduction and increased demand. These temperature projections can be included in PSCo’s load forecasting and load relief planning. Extreme heat also poses a risk to line workers, especially when repairs are required during an extreme heat

event. This can change the periods of maintenance and the required personal protective equipment. Future flooding events may exceed current design standards of assets and submerge them for extended periods of time, and reduce the ability of maintenance crews to access equipment to restore power. Similarly, extreme wind events may also disrupt restoration efforts due to felled vegetation blocking access routes to assets.

This Study adopted a multi-pronged approach to resilience to develop potential resilience measures to address the identified physical and operational vulnerabilities. The multi-pronged resilience approach encompasses four main components: strengthen and withstand, anticipate and absorb, respond and recover, and advance and adapt. Successful resilience measures address one, if not more, of these components. By taking a holistic, multi-faceted approach, PSCo can address weaknesses across the electric system to continue to deliver electricity safely and reliably. Examples of adaptation measures that PSCo can evaluate as a next step include:

- Integrating temperature projections into load forecasting and asset rating processes to determine the need of capacity increase.
- Installing technology such as AMI and SCADA to assist in understanding real-time asset loading and potential changes caused by shifts in temperature in the future.
- Integrate climate risks into portfolio planning and prioritization practices so that future assets are more resilient to climate hazards.
- Review construction design standards and update as needed based on projected flooding.
- Continue practices such as undergrounding and sectionalizing to avoid exposure to climate hazards or reduce the time to recover from an outage, respectively.

A diversity of operational and physical strategies to address climate-related threats and vulnerabilities were identified in this Study which expand upon existing resilience efforts across the Company. Potential next steps may include further refinement and customization of resilience measures to mitigate asset vulnerabilities at specific locations.

Climate science is dynamic and evolving. This analysis uses the best available and most current climate data, which will need to be periodically updated to ensure it continues to accurately capture climate vulnerability and risk across the Company. This Study represents just one part of PSCo’s ongoing resilience journey and provides additional perspective for future capital projects.

APPENDICES

APPENDIX I – CLIMATE SCIENCE VARIABLES AND METHODS

The temperature and precipitation projections used an ensemble of Localized Constructed Analogs Version 2 (LOCA2) downscaled CMIP6 GCMs. The wind and Fire Weather Index (FWI) projections used an ensemble of NEX-GDDP downscaled CMIP6 GCMs. For both sources, the projections consider two SSPs: SSP2-4.5 and SSP5-8.5. The CMIP6 GCMs and SSPs align with the latest climate science developed for the most recent United Nations IPCC Sixth Assessment Report, and NCA5 leverages the LOCA2 dataset. ICF used these datasets to develop projections for tailored temperature, precipitation, and humidity variables based on discussions with PSCo and input from SMEs.

ICF evaluated 15 climate variables associated with different climate hazards and are listed in Table 23. These were selected in coordination with PSCo SMEs based on how each one relates to equipment performance or processes.

Table 23. Climate hazards and their associated variables.

Hazard	Variable
Heat	• Days per year with daily maximum temperature above 95°F • Days per year with daily maximum temperature above 104°F • Number of 2-day or greater heat waves exceeding daily average temperature of 86°F • Duration of a 2-day or greater heat wave exceeding daily average temperature of 86°F • 10-, 30-, 50-, and 100-year daily maximum temperature
Energy Demand	• Annual Heating Degree Days • Annual Cooling Degree Days
Cold Weather	• Number of days with minimum daily temperature below 5°F
Wildfire	• Annual and seasonal (Winter, Spring, Summer, Fall) number of days above historical 95th percentile Fire Weather Index (FWI)
Frozen Precipitation	• Annual maximum frozen precipitation (measurable precipitation with daily mean temperature < 32°F)
Heavy Precipitation	• 1- and 5-day maximum precipitation totals • 25- and 100-year 1-day precipitation totals
Flooding	• 100-year present-day floodplain extent • 500-year present-day floodplain extent
Wind	• Number of days with 1-day average wind speed above historical 90th percentile

APPENDIX II – ASSET EXPOSURE SCORES

Heat

Table 24. Asset exposure score distribution across PSCo service territory for extreme heat.

Time Horizon	SSP2-4.5 50th Asset %						SSP5-8.5 90th Asset %					
	0	1	2	3	4	5	0	1	2	3	4	5
Battery Storage												
2030	50	50	0	0	0	0	50	0	50	0	0	0
2050	50	16.7	33.3	0	0	0	16.7	33.3	0	50	0	0
2080	16.7	33.3	50	0	0	0	0	50	0	0	0	50
Solar Panels												
2030	3.6	81.1	12.8	2.5	0	0	3.3	42.2	50.2	2.4	1.9	0
2050	3.3	64	28.3	3.2	1.1	0	2.1	5.7	41.5	45.8	3	1.9
2080	2.7	19.5	64.2	9.2	4.4	0	1.2	1.6	0.9	2.4	19.2	74.7
Overhead Conductors (line miles)												
2030	28.5	48.4	20.6	2.4	0	0	27.6	22	46.4	2.7	1.2	0
2050	28.1	39.9	27.5	3.2	1.3	0	15.1	18.5	21.6	37.5	5.9	1.5
2080	23.1	16.6	44.7	11.1	4.5	0	7	19.5	4.7	3.3	6.2	59.4
Substations												
2030	17.9	64.7	14.1	3.2	0	0	17.9	29.5	48.7	1.3	2.6	0
2050	17.9	46.8	30.8	1.9	2.6	0	10.9	10.9	33.3	36.5	5.8	2.6
2080	15.4	15.4	53.8	10.9	4.5	0	6.4	10.9	0.6	4.5	12.8	64.7
Underground Conductors (line miles)												
2030	8.7	73.7	15.7	1.9	0	0	8.2	40	47.7	2.7	1.4	0
2050	8.5	59.1	28	2.9	1.4	0	6	4.5	45.3	39.4	3.4	1.4
2080	6.7	20.3	58.9	9.7	4.3	0	4.6	2.5	1.6	2.1	22.6	66.5

Frozen Precipitation

Table 25. Asset exposure score distribution across PSCo service territory for frozen precipitation.

Time Horizon	SSP2-4.5 50th Asset %						SSP5-8.5 90th Asset %					
	0	1	2	3	4	5	0	1	2	3	4	5
Battery Storage												
2030	100	0	0	0	0	0	0	0	0	83.3	16.7	0
2050	100	0	0	0	0	0	0	33.3	50	16.7	0	0
2080	100	0	0	0	0	0	50	0	50	0	0	0
Solar Panels												
2030	94.6	5.4	0	0	0	0	0.1	13.4	28.5	54.8	3.2	0
2050	99.7	0.3	0	0	0	0	9.3	27.2	25.1	33.8	4.5	0
2080	99	0.9	0	0	0	0	63.6	23.3	10	3.1	0	0
Overhead Conductors (line miles)												
2030	97.9	2.1	0	0	0	0	0.5	13.8	34.2	48.9	2.5	0
2050	98.3	1.7	0	0	0	0	12.3	25.4	32.4	29.3	0.6	0
2080	95.9	4.1	0	0	0	0	61.1	20.7	10.9	7.3	0	0
Substations												
2030	95.5	4.5	0	0	0	0	0.6	10.9	32.1	51.9	4.5	0
2050	98.7	1.3	0	0	0	0	12.8	23.1	31.4	30.1	2.6	0
2080	97.4	2.6	0	0	0	0	62.2	20.5	11.5	5.1	0.6	0
Underground Conductors (line miles)												
2030	94.8	5.2	0	0	0	0	0.1	9.4	31.8	52.1	6.7	0
2050	99.7	0.3	0	0	0	0	9.4	27	23.4	34.3	6	0
2080	97.3	2.7	0	0	0	0	57.4	25.8	13.3	3.4	0	0

Extreme Wind

Table 26. Asset exposure score distribution across PSCo service territory for extreme wind.

Time Horizon	SSP2-4.5 50th Asset %						SSP5-8.5 90th Asset %					
	0	1	2	3	4	5	0	1	2	3	4	5
Battery Storage												
2030	0	33.3	33.3	0	33.3	0	0	33.3	0	33.3	33.3	0
2050	0	33.3	33.3	0	33.3	0	0	33.3	16.7	16.7	33.3	0
2080	0	33.3	33.3	0	33.3	0	0	33.3	33.3	0	33.3	0
Solar Panels												
2030	0	0.3	58.1	0.3	41.3	0	0	0.3	12	46.4	41.3	0
2050	0	0.3	58.1	0.3	41.3	0	0	0.3	56.8	1.6	41.3	0
2080	0	0.3	58.1	0.3	41.3	0	0	0.3	58.1	0.3	41.3	0
Overhead Conductors (line miles)												
2030	0	6.5	58.3	3.5	31.8	0	0	6.5	29.8	31.1	32.6	0
2050	0	6.5	58.3	3.5	31.8	0	0	6.5	55.5	6.2	31.8	0
2080	0	6.5	58.3	3.5	31.8	0	0	5.6	56.8	5.5	32	0
Substations												
2030	0	2.6	66.7	0.6	30.1	0	0	2.6	25	42.3	30.1	0
2050	0	2.6	66.7	0.6	30.1	0	0	2.6	59.6	7.7	30.1	0
2080	0	2.6	66.7	0.6	30.1	0	0	2.6	66	1.3	30.1	0
Underground Conductors (line miles)												
2030	0	0.7	63	3.8	32.4	0	0	0.6	15.4	49.8	34.1	0
2050	0	0.7	63	3.8	32.4	0	0	0.7	60	6.9	32.4	0
2080	0	0.7	63	3.8	32.4	0	0	0.6	62.8	4.1	32.4	0

Riverine Flooding

Table 27. Asset exposure score distribution across PSCo service territory for riverine flooding.

Time Horizon	SSP2-4.5 50th Asset %						SSP5-8.5 90th Asset %					
	0	1	2	3	4	5	0	1	2	3	4	5
Battery Storage												
2030	100	0	0	0	0	0	100	0	0	0	0	0
2050	100	0	0	0	0	0	100	0	0	0	0	0
2080	100	0	0	0	0	0	100	0	0	0	0	0
Solar Panels												
2030	98.1	1.4	0.6	0	0	0	98.1	0	0.1	1.8	0	0
2050	98.1	0.1	1.8	0	0	0	98.1	0	0	1.9	0	0
2080	98.1	0	1.9	0	0	0	98.1	0	0	0.9	1.1	0
Overhead Conductors (line miles)												
2030	96.9	3	0.1	0	0	0	88.4	10.2	1.2	0.2	0	0
2050	92.6	6.9	0.4	0	0	0	87.8	10.8	1.3	0.2	0	0
2080	92.6	6.9	0.4	0	0	0	87.1	11.2	1.5	0.2	0	0
Substations												
2030	85.3	10.3	4.5	0	0	0	85.3	0	0	14.7	0	0
2050	85.3	0.6	14.1	0	0	0	85.3	0	0	14.7	0	0
2080	85.3	0	14.7	0	0	0	85.3	0	0	10.9	3.8	0
Underground Conductors												
2030	98.4	1.5	0.1	0	0	0	95.9	3.4	0.4	0.2	0	0
2050	97.1	2.6	0.3	0	0	0	95.9	3.4	0.4	0.2	0	0
2080	97.1	2.6	0.3	0	0	0	95.7	3.3	0.8	0.1	0.1	0

Wildfire

Table 28. Asset exposure score distribution across PSCo service territory for wildfire.

Time Horizon	SSP2-4.5 50th Asset %						SSP5-8.5 90th Asset %					
	0	1	2	3	4	5	0	1	2	3	4	5
Battery Storage												
2030	33.3	50	16.7	0	0	0	33.3	0	66.7	0	0	0
2050	33.3	0	66.7	0	0	0	33.3	0	66.7	0	0	0
2080	33.3	0	66.7	0	0	0	33.3	0	0	66.7	0	0
Solar Panels												
2030	40.5	41.6	17.1	0.8	0	0	40.5	0	54.9	4.5	0.1	0
2050	40.5	1	56.9	1.5	0.1	0	40.5	0	52.2	6.5	0.8	0
2080	40.5	0	58	1.5	0.1	0	40.5	0	3.2	54.8	1.5	0.1
Overhead Conductors (line miles)												
2030	40.5	41.6	17.1	0.8	0	0	40.5	0	54.9	4.5	0.1	0
2050	40.5	1	56.9	1.5	0.1	0	40.5	0	52.2	6.5	0.8	0
2080	40.5	0	58	1.5	0.1	0	40.5	0	3.2	54.8	1.5	0.1
Substations												
2030	32.1	39.7	27.6	0.6	0	0	32.1	0	63.5	4.5	0	0
2050	32.1	4.5	60.3	3.2	0	0	32.1	0	52.6	14.7	0.6	0
2080	32.1	0	64.7	3.2	0	0	32.1	0	3.8	60.9	3.2	0
Underground Conductors (line miles)												
2030	36.8	53.3	9.7	0.3	0	0	26.1	24.7	47.5	1.7	0	0
2050	30.7	40	27.6	1.7	0	0	25.7	20.6	51.2	2.3	0.3	0
2080	29.4	35.5	33.4	1.7	0	0	21.5	17.1	21.8	37.9	1.7	0

APPENDIX III – ASSET SENSITIVITY

Sensitivities are defined for multiple relevant natural hazard categories. The criteria for sensitivity ratings were defined as follows:

- (0) **Not Applicable** sensitivity is for assets that are not affected by a given climate hazard.
- (1) **Low** sensitivity refers to assets, operations, or systems facing minimal potential adverse impact from a given climate hazard.
- (2) **Moderate** sensitivity refers to assets, operations, or systems that may be adversely affected by a given climate hazard. Impacts are moderated by one or more factors, such as impacts being only likely at a very high threshold of exposure (e.g., very high temperature or water level) or being more likely to be chronic or controlled than sudden or acute (e.g., accelerated degradation rather than catastrophic failure).
- (3) **High** sensitivity refers to assets, operations, or systems that may be subject to increased likelihood of major and/or sudden failure in the event of hazard exposure, even at lower thresholds. The asset is bound to have limited existing tolerance for exposure to this hazard (e.g., pad-mount transformers and flooding).

Extreme Heat

Table 29. Asset sensitivity to extreme heat.

Asset	Extreme Heat	Extreme Cold	Frozen Precipitation	Extreme Wind	Riverine Flooding	Wildfire
Distribution						
Distribution poles	0	0	2	2	2	3
Overhead Conductors	2	0	3	2	1	2
Overhead Transformers	2	1	2	1	1	2
Pad-mount Transformers	2	1	0	0	3	3
Substation						
Substation Transformers and Regulators	2	1	2	1	2	1
Circuit Breakers	1	1	2	1	2	2
Protection and Control Devices	1	0	0	1	2	1
Control Rooms/Control Houses	1	1	0	1	3	1

Asset	Extreme Heat	Extreme Cold	Frozen Precipitation	Extreme Wind	Riverine Flooding	Wildfire
DERs						
Battery Storage	0	1	1	0	3	3
Solar Panels	0	0	2	3	2	3

APPENDIX IV – VULNERABILITY SCORES

The thresholds for asset vulnerability ratings were defined as follows:

- Low: Assets with vulnerability scores between 0 and 10
- Medium: Assets with vulnerability scores between 10 and 20
- High: Assets with vulnerability scores of 20 and above

Heat

Table 30. Asset vulnerability score distribution across PSCo service territory for extreme heat.

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
DISTRIBUTION						
Overhead Conductors						
2030	97%	3%	0%	96%	4%	0%
2050	95%	5%	0%	49%	51%	0%
2080	84%	16%	0%	24%	76%	0%
Overhead Transformers						
2030	97%	3%	0%	95%	5%	0%
2050	95%	5%	0%	46%	54%	0%
2080	83%	17%	0%	22%	78%	0%
Pad-mount Transformers						
2030	97%	3%	0%	95%	5%	0%
2050	95%	5%	0%	52%	48%	0%
2080	85%	15%	0%	8%	92%	0%
SUBSTATION						
Substation Transformers						
2030	87%	13%	0%	67%	30%	3%
2050	78%	19%	3%	25%	63%	12%
2080	46%	49%	5%	18%	4%	78%

Frozen Precipitation

Table 31. Asset vulnerability score distribution across PSCo service territory for ice.

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
DISTRIBUTION						
Poles						
2030	100%	0%	0%	47%	53%	0%
2050	100%	0%	0%	67%	33%	0%
2080	100%	0%	0%	94%	6%	0%
Overhead Conductors (line miles)						
2030	100%	0%	0%	17%	80%	3%
2050	100%	0%	0%	42%	57%	1%

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
2080	100%	0%	0%	86%	14%	0%
SUBSTATION						
Substation Transformers						
2030	100%	0%	0%	12%	84%	4%
2050	100%	0%	0%	36%	62%	2%
2080	100%	0%	0%	83%	16%	1%
Circuit Breakers						
2030	100%	0%	0%	44%	56%	0%
2050	100%	0%	0%	67%	33%	0%
2080	100%	0%	0%	94%	6%	0%
DERs						
Solar Panels						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%

Extreme Wind

Table 32. Asset vulnerability score distribution across PSCo service territory for extreme wind.

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
DISTRIBUTION						
Poles						
2030	62%	38%	0%	25%	75%	0%
2050	62%	38%	0%	60%	40%	0%
2080	62%	38%	0%	61%	39%	0%
Overhead Conductors (line miles)						
2030	58%	42%	0%	30%	70%	0%
2050	58%	42%	0%	56%	44%	0%
2080	58%	42%	0%	57%	43%	0%
DERs						
Solar Panels						
2030	59%	41%	0%	58%	42%	0%
2050	59%	41%	0%	59%	41%	0%
2080	59%	41%	0%	59%	41%	0%

Riverine Flooding

Table 33. Asset vulnerability score distribution across PSCo service territory for riverine flooding.

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
DISTRIBUTION						
Poles						
2030	100%	0%	0%	94%	6%	0%
2050	100%	0%	0%	93%	7%	0%
2080	100%	0%	0%	93%	7%	0%
Pad-mount Transformers						
2030	99%	1%	0%	97%	3%	0%
2050	97%	3%	0%	97%	3%	0%
2080	97%	3%	0%	97%	2%	1%
SUBSTATION						
Substation Transformers						
2030	95%	5%	0%	85%	15%	0%
2050	86%	14%	0%	85%	15%	0%
2080	85%	15%	0%	85%	11%	4%
Circuit Breakers						
2030	100%	0%	0%	85%	15%	0%
2050	100%	0%	0%	85%	15%	0%
2080	100%	0%	0%	85%	15%	0%
Protection & Control Devices						
2030	95%	5%	0%	85%	15%	0%
2050	86%	14%	0%	85%	15%	0%
2080	85%	15%	0%	85%	11%	4%
Control Rooms						
2030	95%	5%	0%	85%	0%	15%
2050	86%	14%	0%	85%	0%	15%
2080	85%	15%	0%	85%	0%	15%
DERs						
Battery Storage						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
Solar Panels						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%

Wildfire

Table 34. Asset vulnerability score distribution across PSCo service territory for wildfire.

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
DISTRIBUTION						
Poles						
2030	96%	4%	0%	62%	37%	1%
2050	94%	6%	0%	50%	48%	2%
2080	82%	18%	0%	45%	51%	4%
Overhead Conductors (line miles)						
2030	98%	2%	0%	97%	3%	0%
2050	97%	3%	0%	93%	7%	0%
2080	97%	3%	0%	73%	27%	0%
Overhead Transformers						
2030	99%	1%	0%	96%	4%	0%
2050	96%	4%	0%	94%	6%	0%
2080	96%	4%	0%	74%	26%	0%
Pad-mount Transformers						
2030	98%	2%	0%	50%	49%	0%
2050	96%	3%	0%	44%	56%	1%
2080	86%	14%	0%	39%	59%	2%
DERs						
Solar Panels						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	99%	1%	0%
2080	100%	0%	0%	98%	2%	0%

APPENDIX V – OPERATIONAL VULNERABILITY

PLANNING

Load Forecasting

Relevant Operational Characteristics: Load forecasting is the process of forecasting customer peak demand and energy based on customer behavior and weather conditions. To make these forecasts, the Company relies on historical weather data, customer usage trends, and planned new customer connections.

Relevant Climate Hazards: Extreme Heat

Climate Vulnerability: PSCo includes historical weather in the forecasting process to produce "weather normalized" forecasts that project peak demand and energy for a "normal" weather day. Ambient temperature is a significant driver of peak demand and energy. PSCo uses a 10-year average of monthly Cooling Degree Days (CDDs) and Heating Degree Days (HDDs) at Denver International Airport in its sales models. For this forecast, the 10-year period is from 2010-2019. The Company uses a 30-year average of monthly maximum daily CDDs and HDDs for its peak demand models, based on data at Stapleton. For this forecast, the 30-year period is 1990–2019.[6] Both maximum and average temperatures are projected to rise across the PSCo service territory starting as soon as 2030 and increasing through 2080. These temperature increases will lead to potentially massive deviations from historical weather trends, resulting in hotter summers and warmer winters, potentially shifting demand associated with home heating and cooling. Without the use of projections in load forecasting models, PSCo risks inaccurately forecasting peak demand and energy. Under forecasting peak demand could result in overloads during summer periods. Overloads may reduce equipment lifespan or even impact reliability. Under forecasting energy, could result in mismatches between supply and demand which could impact energy economics and even reliability.

Potential Risk Mitigation Options: PSCo could incorporate climate projections into the load forecasting process to reduce the risks described above. Additionally, the use of technology such as AMI and SCADA can greatly assist in understanding real-time system and asset loading and potential changes caused by shifts in temperature.

Load Relief Planning

Relevant Operational Characteristics: Load relief planning is the process of identifying where demand is forecasted to exceed equipment or system ratings and selecting actions to address overloads. This process relies on a combination of peak demand forecasts and equipment ratings, which are themselves dependent on ambient temperature assumptions.

Relevant Climate Hazards: Extreme Heat

[6] PSCo 2021 Electric Resource Plan and Clean Energy Plan, Volume 2 Technical Appendix

Climate Vulnerability: PSCo assumes an average ambient temperature of 86°F when determining ratings for substation transformers and 104°F with windspeeds of 2 feet-per-second when determining ratings for overhead distribution feeders. These assumptions are uniform across the PSCo service territory.

Heat waves are expected to increase in both their frequency, intensity, and duration, and maximum and average temperatures are also projected to rise across the PSCo service territory starting as soon as 2030 and increasing through 2080. Such increases will increase the frequency with which PSCo assets are exposed to ambient temperatures above those assumed when determining ratings. Extreme heat events can result in decreases in capacity of transformers and conductors while simultaneously increasing demand, potentially requiring load shedding to avoid equipment damage, as was done by Avista utilities during the 2021 Spokane heat wave. PSCo's uniform use of fixed ambient temperatures for determining ratings across the service territory, which does not account for regional variations in ambient temperatures may overlook hot spots in ambient temperature that may exist across the service territory that may be exacerbated by climate change.

Potential Risk Mitigation Options: To anticipate potential changes in load and capacity due to climate change, the Company should incorporate climate projections into load relief and capacity planning efforts and ensure equipment ratings are appropriate to manage higher temperatures and the associated decreases in capacity and increases in demand. Additionally, real-time insight into asset loading through technology such as SCADA and AMI, and accurate information on customer characteristics (i.e., critical customers, disadvantaged communities, and customers using home medical equipment) is crucial to both plan for load relief/capacity as well as manage load shedding.

Portfolio Planning and Prioritization

Relevant Operational Characteristics: Portfolio Planning and Prioritization is the process of planning, evaluating, and ranking various investment opportunities using cost-benefit analysis or multi-criteria decision framework to optimize the allocation of resources given planning objectives.

Relevant Climate Hazards: Extreme Heat, Ice, Extreme Wind, Riverine Flooding, Wildfire

Climate Vulnerability: As extreme weather events become more frequent and severe, it will become increasingly important to ensure that investments in adaptation measures to bolster the resilience of the grid are prioritized. Many utilities use investment prioritization frameworks that favor projects that prioritize short-term risks based on historical events. Without modification of investment processes to account for long-term climate-informed risks, resilience measures may not receive necessary capital allocations, and the system can become ill equipped to confront the risks posed by climate change. Additionally, the increasing severity and frequency of damaging extreme weather events may result in higher short-term costs for the Company as the need to repair and replace damaged assets may grow. These growing costs may result in impacts to capital budgets and thus may influence the way projects are prioritized.

Potential Risk Mitigation Options: Ensuring that long-term climate-informed risks are explicitly considered as a factor in current portfolio planning and prioritization practices can help ensure adequate investment in bolstering the resilience of the grid. Additionally, as resilience investments often pay high dividends over the long term and can be far less expensive than post-event recovery and repairs, ensuring accurate cost-effectiveness for adaptation strategies will be critical to accurately reflect the costs and benefits of climate change.

ENGINEERING AND DESIGN

Asset Ratings

Relevant Operational Characteristics: Asset Ratings is the process of determining the energy delivery capacity of Transmission and Distribution assets and systems and the environmental conditions assets may face. Ratings are based on a set of assumptions which include climate factors such as ambient temperature and average wind speeds.

Relevant Climate Hazards: Extreme Heat, Wind

Climate Vulnerability: As climate change causes both increased temperatures and wind speeds to deviate from their historical norms, asset ratings that have been determined based on historical weather data may become out of date. Increased temperatures are expected to cause increases in demand and decreases in capacity of conductors and transformers, potentially pushing assets beyond their temperature ratings, resulting in potential damage, failure, or load shedding. Similarly, overhead assets are often rated to historical windspeed standards. As wind speeds increase, these ratings may also be exceeded, resulting in damaged equipment and potential outages.

Potential Risk Mitigation Options: Incorporating forward-looking climate projections into the asset rating process is critical to ensuring that asset ratings continue to be responsive to changing climate conditions. While updated asset ratings will ensure that new assets are more resilient to climate hazards, it will also be critical to retrofit or replace older assets that are rated to previous standards.

Flood Design

Relevant Operational Characteristics: Flood Design is the process of designing infrastructure and systems to withstand flooding conditions based on historical data, forward-looking projections, and flood risk assessments.

Relevant Climate Hazards: Riverine Flooding

Climate Vulnerability: Increased precipitation is expected to cause more frequent and severe flooding within the service territory, exposing assets in the floodplain to flood conditions at more frequent rates with potentially greater flood depths, and potentially exposing assets to flood conditions that were previously outside of the historical floodplain. Current flood standards that are in place may be exceeded and assets that

currently are not designed to withstand flooding may need to be retrofitted to include flood protection measures.

Potential Risk Mitigation Options: Designing and siting assets in a way that is responsive to flood conditions will become increasingly important as flooding is expected to increase in frequency and severity. The Company should consider forward-looking flood projections that consider both the historical floodplain and future precipitation projections when creating flood siting and design standards. Existing and future assets should both be reviewed to assess their vulnerability to flooding and adaptation measures should be taken when necessary.

Reliability Assessment and Planning

Relevant Operational Characteristics: Reliability Assessments and Planning include activities to achieve reliability performance targets, project future reliability performance, and identify investments to meet reliability performance targets.

Relevant Climate Hazards: Extreme Heat, Ice, Extreme Wind, Riverine Flooding, and Wildfire

Climate Vulnerability: Climate change is expected to increase the frequency and severity of extreme weather events (including heat waves, frozen precipitation, extreme winds, riverine flooding, and wildfire). These weather events can result in outages and impact reliability. Without adequate resilience measures to account for the increased frequency and severity of these events, reliability could fall substantially under performance targets.

Potential Risk Mitigation Options: Increasing adaptation measures that address specific hazards, such as flood design measures or increased wind ratings, in addition to general redundancies in the system such as increasing substation design standards to N-1 or N-2 and increasing the number of looped feeders in the system can greatly reduce disruptions and help PSCo continue to meet its reliability targets. Additionally, use of modeling to better predict possible disruptions can also help reduce outages and inform reliability planning.

OPERATIONS

Work Practices and Safety

Relevant Operational Characteristics: Work practices and safety standards are the policies and procedures designed to keep utility workers safe and healthy while performing their jobs. These include but are not limited to guidelines about the use of personal protective equipment (PPE), procedures to take in response to different weather conditions, and how to safely handle high voltage and hazardous equipment.

Relevant Climate Hazards: Extreme Heat, Ice, Extreme Wind, Riverine Flooding, and Wildfire

Climate Vulnerability: The projected increasingly frequent and severe weather events caused by climate change are likely to cause unsafe conditions for utility workers, especially those in the field, such as line workers. Current work practices and safety standards often address conditions based on historical weather events and past safety failures. While many of these practices, especially those regarding storm conditions or handling of high volage and hazardous equipment, consider worst case scenarios, the assumptions which they protect against may be surpassed as exposure to unsafe conditions is expected to increase. Additionally, some safety standards may not address all hazards that are projected to increase due to climate change, such as extreme heat, which is the leading cause of climate change-related deaths globally. Lastly, more severe and frequent extreme weather events may create hazardous conditions for non-field employees to get to their offices.

Potential Risk Mitigation Options: To ensure that workers are continuously kept safe, PSCo should consider new potential worst-case scenarios caused by climate change-related extreme weather events as well as potential risks that may be present on a day-to-day basis (such as increased average temperatures). Worker safety standards and practices should be updated accordingly for both workers in the field as well as office employees. As there is a certain degree of variability in climate projections and no safety standard can predict all outcomes, these standards should be routinely revisited and updated to reflect changing conditions on the ground as well as updates from new scientific models and data as they become available.

Emergency Preparedness, Response, and Restoration

Relevant Operational Characteristics: Emergency Preparedness, Response, and Restoration includes activities to prepare and respond to adverse events that affect the electrical system, including extreme weather. Includes event preparedness, damage assessment, repairs, restoration of service, mutual assistance, and partnerships local governments and emergency services.

Relevant Climate Hazards: Extreme Heat, Ice, Wind, Riverine Flooding, and Wildfire

Climate Vulnerability: The projected increasing frequency and severity of extreme weather events including heat waves, ice storms, high winds, riverine flooding, and wildfire events, will lead to increased emergency activations for the Company. The frequency and magnitude of the events may strain current emergency response resources and may result in increased costs for the Company to repair and replace damaged assets and compensate staff for overtime hours. As climate change will affect areas beyond the service territory, mutual aid may also become limited at times, especially during widespread regional extreme weather events that affect multiple utilities in the region. Additionally, frequent emergency activations may become disruptive to normal utility operations as non-emergency personnel more frequently assume their gray-sky roles and are taken away from their normal blue-sky duties.

Potential Risk Mitigation Options: To prepare for potential impacts to emergency response procedures, it is critical that the Company allocates appropriate funding and

staffing resources to confront the increased threats posed by climate-related extreme weather events. Additionally, the use of advanced technologies to better anticipate emergency events and more efficiently prepare and respond to disruptions can greatly streamline emergency response efforts.

Vegetation Management

Relevant Operational Characteristics: Vegetation management involves maintaining the vegetation along rights-of-way to reduce the risk of trees contacting lines. Management activities include trimming and removal of dead, dying, or defective trees.

Relevant Climate Hazards: Extreme Heat, Ice, Wind, Wildfire

Climate Vulnerability: Project average temperature increases in the service areas may result in changes in growing cycles leading to faster tree growth and decreased wood density (which weakens trees, making them more susceptible to extreme weather events). Changes in climate can also result in the spread of invasive species, such as the Emerald Ash Borer (which can cause widespread tree damage and death, heightening the likelihood of contact with overhead lines). Projected increases in wind may also cause trees to fall on and damage overhead lines. This risk can be compounded by oversaturated soil resulting from extreme precipitation in severe weather events. Lastly, as wildfire risk is projected to increase across the service territory and vegetation is expected to increase with a warming climate, vegetation management will become even more critical to limit wildfire spread and ensure that vegetation does not cause ignition through contact with grid infrastructure.

Potential Risk Mitigation Options: Establishing a climate-responsive vegetation management program is critical. Rather than a time-cycle based program, a condition-based program should be implemented to adapt to the increasing variability in climate and severe events. Additional risk mitigation options include procuring additional easement rights to widen rights-of-way, expanding clearances, adopting new technologies to identify clearance violations (such as satellite monitoring or LiDAR), and installing more aerial cable or tree wire.

Asset Management

Relevant Operational Characteristics: Asset management involves monitoring and maintaining transmission, distribution, and substation assets and systems to ensure they meet performance standards. Monitoring and maintenance activities include inspections, gathering inventory information, recognizing changes and trends in asset performance, developing methods to identify asset issues prior to failures, developing and applying maintenance programs, and managing field work.

Relevant Climate Hazards: Extreme Heat, Ice, Extreme Wind, Riverine Flooding, and Wildfire

Climate Vulnerability: All climate hazards have the potential to increase asset damage and failure rates, which may require the Company to increase asset replacement rates. Projected increases in temperature can degrade wood poles, reduce transformer capacity, and prematurely age assets. Projected increases in frozen precipitation can lead to ice accumulation on poles, causing increased loading and damage. Icing can also lead to flashovers on transmission level bushings and insulators and can cause switches to

freeze. Increased extreme winds may lead to higher rates of pole failures. Riverine flooding can compromise structural integrity of poles and corrode and flood underground assets. Wildfires can threaten pole integrity and damage ground-based assets. Even assets elevated above ground level are at risk if contact occurs with susceptible vegetation. Many utilities in the United States are also experiencing supply chain issues for some assets, such as transformers. Impacts of climate change on assets may increase demand for replacement assets, only worsening supply chain issues. Extreme weather events caused by climate change can also impact global supply chains, potentially compounding asset shortages.

Potential Risk Mitigation Options: Designing an asset management system and comprehensive failure database should be a priority to understand and track asset failure. This data can then be used to prioritize resilience investments. Comprehensive health indices to track the condition and project future asset failures should also be developed. A potential risk mitigation option is implementing measures for storm hardening. Storm hardening measures can include using fiberglass crossarms on distribution poles to preserve poles during storm events, upgrading pole classes when necessary, and various design changes to allow for enhanced mechanical coordination between system components. Additionally, investing in capital and Operation and Maintenance programs, such as targeted end-of-life replacement for poorly performing assets, can help remove weak points in the system, thereby enhancing overall resilience. Lastly, remote condition assessment technologies can be used to monitor temperature-related asset changes.

APPENDIX VI – RISK SCORES TABLES

The thresholds for asset risk score ratings were defined as follows:

- Low: Assets with risk scores between 0 and 20
- Medium: Assets with risk scores between 20 and 50
- High: Assets with risk scores of 50 and above

Heat

Table 35. Asset risk score distribution across PSCo service territory for extreme heat.

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
DISTRIBUTION						
Overhead Conductors (line miles)						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	95%	5%	0%
Overhead Transformers						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	98%	2%	0%
Pad-mount Transformers						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	99%	1%	0%
SUBSTATION						
Substation Transformers						
2030	100%	0%	0%	99%	1%	0%
2050	99%	1%	0%	91%	9%	0%
2080	94%	6%	0%	67%	33%	0%

Frozen Precipitation

Table 36. Asset risk score distribution across PSCo service territory for ice.

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
DISTRIBUTION						
Poles						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
Overhead Conductors (line miles)						
2030	100%	0%	0%	81%	19%	0%
2050	100%	0%	0%	87%	13%	0%

2080	100%	0%	0%	99%	1%	0%
			SUBSTATION			
			Substation Transformers			
2030	100%	0%	0%	96%	4%	0%
2050	100%	0%	0%	95%	5%	0%
2080	100%	0%	0%	100%	0%	0%
			Circuit Breakers			
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
			DERs			
			Solar Panels			
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%

Extreme Wind

Table 37. Asset risk score distribution across PSCo service territory for extreme wind.

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
			DISTRIBUTION			
			Poles			
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
			Overhead Conductors (line miles)			
2030	99%	1%	0%	98%	2%	0%
2050	99%	1%	0%	99%	1%	0%
2080	99%	1%	0%	99%	1%	0%
			DERs			
			Solar Panels			
2030	97%	3%	0%	97%	3%	0%
2050	97%	3%	0%	97%	3%	0%
2080	97%	3%	0%	97%	3%	0%

Riverine Flooding

Table 38. Asset risk score distribution across PSCo service territory for riverine flooding.

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
DISTRIBUTION						
Poles						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
Pad-mount Transformers						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
SUBSTATION						
Substation Transformers						
2030	100%	0%	0%	94%	6%	0%
2050	100%	0%	0%	94%	6%	0%
2080	100%	0%	0%	94%	6%	0%
Circuit Breakers						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
Protection & Control Devices						
2030	100%	0%	0%	94%	6%	0%
2050	100%	0%	0%	94%	6%	0%
2080	100%	0%	0%	94%	6%	0%
Control Rooms						
2030	98%	2%	0%	94%	6%	0%
2050	94%	6%	0%	94%	6%	0%
2080	94%	6%	0%	93%	7%	0%
DERs						
Battery Storage						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
Solar Panels						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%

Wildfire

Table 39. Asset risk score distribution across PSCo service territory for wildfire.

	SSP2-4.5 50th Asset %			SSP5-8.5 90th Asset %		
Time Horizon	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
DISTRIBUTION						
Poles						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	96%	4%	0%
Overhead Conductors (line miles)						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
Overhead Transformers						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
Pad-mount Transformers						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	97%	3%	0%
DERs						
Battery Storage						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%
Solar Panels						
2030	100%	0%	0%	100%	0%	0%
2050	100%	0%	0%	100%	0%	0%
2080	100%	0%	0%	100%	0%	0%

REFERENCES

[1] Xcel Energy. “2025-2027 Colorado Wildfire Mitigation Plan.” https://xcelnew.my.salesforce.com/sfc/p/#1U0000011ttV/a/8b000002gSjb/TL6bvrU3whD8M6_xSOVgXDEpj4pCqH7vXBPSfJHK0h4

[2] Colorado Department of Public Health & Environment (May 4th, 2023). “Governor Polis signs new definition of disproportionately impacted community into law”. https://cdphe.colorado.gov/enviroscreen

[3] Pierce, D. W., Su, L., Cayan, D. R., Risser, M. D., Livneh, B., & Lettenmaier, D. P. (2021). An Extreme-Preserving Long-Term Gridded Daily Precipitation Dataset for the Conterminous United States. Journal of Hydrometeorology, 22(7), 1883-1895. https://doi.org/10.1175/JHM-D-20-0212.1

[4] Thrasher, B., Wang, W., Michaelis, A., Melton, F., Lee, T., & Nemani, R. (2022). NASA Global Daily Downscaled Projections, CMIP6. Scientific Data, 9(1), 1-6. https://doi.org/10.7917/OFSG3345

[5] UNFCCC, “The Shared Socioeconomic Pathways (SSPs): An Overview,” https://unfccc.int/sites/default/files/part1_iiasa_rogelj_ssp_poster.pdf

[6] CO Department of Public Health and Environment. (2024). Extreme heat resources and references. Retrieved from https://cdphe.colorado.gov/health-facilities/emergency-preparedness/extreme-heat-resources-and-references

[7] Pielke, R.A., Wolter, K., Bliss, O., Doesken, N., McNoldy, B. (2005). “July 2005 Denver Heat Wave: How Unusual Was It?,” NWA National Weather Digest, https://climate.colostate.edu/pdfs/Denver%20Heat%20Wave_21Nov2005_final.pdf.

[8] CO Department of Public Health and Environment. (2024). Extreme heat resources and references. Retrieved from https://cdphe.colorado.gov/health-facilities/emergency-preparedness/extreme-heat-resources-and-references

[9] Colorado Climate Center. (2003). Climate of Colorado. Retrieved from https://climate.colostate.edu/climate_long.html#:~:text=The%20highest%20temperatures%20in%20Colorado,Sedgwick%20on%20July%2011%2C%201954.

[10] NOAA. (2024 - a). NOAA Storm events database. Retrieved from https://www.ncdc.noaa.gov/stormevents/eventdetails.jsp?id=5434363

[11] NOAA. (2024-b). NOAA Storm events database. Retrieved from https://www.ncdc.noaa.gov/stormevents/eventdetails.jsp?id=676683

[12] NOAA. (2024). NOAA Storm events database. Retrieved from https://www.ncdc.noaa.gov/stormevents/eventdetails.jsp?id=676620

[13] NOAA. (2024-c). NOAA Storm events database. Retrieved from https://www.ncdc.noaa.gov/stormevents/eventdetails.jsp?id=676683

[14] National Weather Service. (2020). “January 9th Rare Ice Storm Summary,” Retrieved from https://www.weather.gov/gjt/Jan09_IceStorm

[15] FEMA. (2024). The National Risk Index. Retrieved from https://hazards.fema.gov/nri/

[16] Bilek, C. (2023). Why are some places in Colorado always so Windy? Retrieved from https://www.cpr.org/2023/03/10/colorado-windy-places/

[17] Adams, W. (2024). Unraveling Colorado’s Windy secrets: Navigating nature’s powerful gusts. Retrieved from https://kekbfm.com/colorado-fastest-wind-speed/#:~:text=Colorado’s%20Fastest%20Official%20Wind%20Speed&text=The%20fastest%20official%20wind%20speed,an%20elevation%20of%2011%2C312%20feet.

[18] NOAA. (2021). Extreme wind event. Retrieved from https://www.weather.gov/pub/ExtremeWindEvent_20211215

[19] Blumhardt, M. (2024). Power outages from Colorado’s weekend windstorm continue Monday. Retrieved from https://www.usatoday.com/story/news/2024/04/08/these-were-the-top-wind-gusts-in-colorado-during-weekend-storm/73241592007/

[20] CO Department of Natural Resources. (2024). Flood Information & Resources. Retrieved from https://cwcb.colorado.gov/focus-areas/hazards/flood-information-resources#:~:text=Flood%2Dprone%20areas%20have%20been,and%20in%20all%2064%20counties.

[21] Tyler, S. (2023). “almost unimaginable”: The 2013 Colorado Flood, 10 years later • colorado newsline. Retrieved from https://coloradonewsline.com/2023/09/05/almost-unimaginable-the-2013-colorado-flood-10-years-later/

[22] Tyler, S. (2023). “almost unimaginable”: The 2013 Colorado Flood, 10 years later • colorado newsline. Retrieved from https://coloradonewsline.com/2023/09/05/almost-unimaginable-the-2013-colorado-flood-10-years-later/

[23] Slevin, C., Bedayn, J., & Gruver, M. (2023). Colorado’s most destructive wildfire caused by embers from old fire, sparks from power line. Retrieved from https://apnews.com/article/marshall-fire-colorado-cause-91aad87da67fd883b9294df1ff386865

[24] Western Fire Chiefs Association. (2024). Colorado fire season: In-depth guide. Retrieved from https://wfca.com/wildfire-articles/colorado-fire-season/#:~:text=There%20are%20growing%20hotspots%20near,seasons%20and%20threaten%20populated%20areas.

[25] Meckles, J. (2023). Colorado homes are at high fire risk, report says | 9news.com. Retrieved from https://www.9news.com/article/news/local/wildfire/report-high-fire-risk-colorado-homes/73-5d1e4b47-9fd1-41b0-9ec1-27cc06970475

[26] Avitt, A. (2021). Cameron Peak: Fighting fire together. Retrieved from https://www.fs.usda.gov/features/cameron-peak-fighting-fire-together

[27] NOAA Research. (2024). “Looking back at Colorado’s Marshall Fire,” https://research.noaa.gov/2024/01/08/looking-back-at-colorados-marshall-fire/

[28] Scott, Joe H.; Gilbertson-Day, Julie W.; Moran, Christopher; Dillon, Gregory K.; Short, Karen C.; Vogler, Kevin C. 2020. Wildfire Risk to Communities: Spatial datasets of landscape-wide wildfire risk components for the United States. Fort Collins, CO: Forest Service Research Data Archive. https://doi.org/10.2737/RDS-2020-0016

[29] NOAA. (2022). Extreme wind chill readings December 22-23, 2022. Retrieved from https://www.weather.gov/bou/ExtremeWindChillReadingsReportsDecember22_2022#:~:text=Life%20threatening%20wind%20chills%20were,in%205%20minutes%20or%20less.

[30] National Weather Service. (n.d.). Retrieved from https://www.weather.gov/media/bou/February2021ClimateSummary.pdf

[31] NOAA. (2022). Extreme wind chill readings December 22-23, 2022. Retrieved from https://www.weather.gov/bou/ExtremeWindChillReadingsReportsDecember22_2022#:~:text=Life%20threatening%20wind%20chills%20were,in%205%20minutes%20or%20less.

[32] Peterson, J. (2021). “Avalanche Damage Triggers Constructability Improvements.” *T&D World.* https://www.tdworld.com/overhead-transmission/article/21173435/avalanche-damage-triggers-constructability-improvements

[33] Francis, J. A., & Vavrus, S. J. (2012). Evidence linking Arctic amplification to extreme weather in mid-latitudes. *Geophysical Research Letters*, 39(6). https://doi.org/10.1029/2012GL051000

[34] Brooks, N. (2003). Vulnerability, risk and adaptation: A conceptual framework. Tyndall Centre for Climate Change and Research. https://www.ipcc.ch/apps/njlite/srex/njlite_download.php?id=5463

[35] IPCC, 2018: Annex I: Glossary [Matthews, J.B.R. (ed.)]. In: Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)]. Cambridge University Press, Cambridge, UK and New York, NY, USA, pp. 541-562. https://doi.org/10.1017/9781009157940.008.

[36] FEMA (2023). Emergency Management: Community Lifelines. Retrieved from: Lifelines Implementation Toolkit v2.1 (fema.gov)

Appendix 7 - Technical Working Group Facilitator's Report

GRIDWORKS

Independent Facilitator's Technical Working Group Final Report

A Deliverable for Public Service Company of Colorado's Per the Distribution System Plan Settlement Agreement

Proceeding No. 22A-0189E

May 23, 2024

Colorado PUC E-Filings System

Submitted by:
Gridworks
PO Box 5013
Berkeley, CA 94705
info@gridworks.org

TABLE OF CONTENTS

TABLE OF CONTENTS **2**
ACKNOWLEDGEMENTS **2**
DEFINITION OF TERMS **2**
INTRODUCTION **3**
TECHNICAL TOPIC MEETING SUMMARIES **4**
1. DRMS Requirements / Follow up on Pay for Performance 5
2. Flexible Interconnection 7
3. Pilots - Third Party Proposals 10
4. Unintentional Islanding 12
5. Hosting Capacity Analysis and 15/15 Updates 14
REFLECTIONS **16**
Progress on Technical Working Group's Objectives 16
Enhancing Impact of Future Technical Working Groups 18
APPENDIX A: MEETING ATTENDANCE **19**

ACKNOWLEDGEMENTS

Gridworks would like to thank all of the participants in this technical working group. We extend extra gratitude to the following Colorado Public Utilities Commission (CO PUC) and Xcel Energy staff for their help in planning and conducting the working group meetings.

- Joe McCabe, CO PUC
- Jack Turner, CO PUC
- Beth Chacon, Xcel Energy
- Meghan Corrigan, Xcel Energy
- Jessica Lau, Xcel Energy
- Zach Pollock, Xcel Energy

DEFINITION OF TERMS

Distributed Energy Resource Management System ("DERMS") - DERMS is an emerging category of operational software and hardware platform that is expected to provide enhanced situational awareness, DER monitoring, control, analytics, and optimization capabilities to distribution system operators.[1]

Demand Response Management System ("DRMS") - DRMS is a software control platform capable of aggregating multiple types of DER to provide demand reduction or load shifting benefits at the bulk-system or distribution system level. These platforms also typically handle

[1] See Public Service Company of Colorado, Distribution System Plan, May 2, 2022, at p. 17.

customer enrollment of devices (e.g. smart thermostats, electric vehicle chargers, etc.), and event dispatch.[2]

Flexible Interconnection ("FI") - Flexible Interconnection is a DER control strategy used to defer or avoid system upgrades necessary for interconnection and increase distributed energy resource ("DER") integration.[3]

Hosting Capacity Analysis ("HCA") - Hosting capacity is the amount of distributed photovoltaic ("DPV") that can be added to the distribution system before control changes or system upgrades are required to safely and reliably integrate additional DPV.[4]

Unintentional Islanding ("UI") - When a portion of the electric distribution system is separated from the rest of the grid but remains energized by a generator until the generator is tripped.[5]

Virtual Power Plant ("VPP") - A collection of distributed resources that can be dispatched in response to a control signal.[6]

INTRODUCTION

In February 2023, the Colorado Public Utilities Commission ("Commission") approved the inaugural Distribution System Plan ("DSP") filed by Public Service Company of Colorado ("the Company", or "Xcel Energy") in Commission Proceeding No. 22A-0189E. The Commission's order also approved a Settlement Agreement and Joint Stipulation between Xcel Energy and stakeholders that resolved all issues in the DSP proceeding. As part of the Settlement Agreement, the Company and stakeholders agreed to establish a Technical Working Group (TWG) to discuss several topics identified through the settlement process.

The Company also agreed to select an independent, third-party to facilitate the technical working group, and in May 2023 Gridworks was selected through a competitive solicitation to serve as facilitator. The Settlement Agreement identifies the third party's role to facilitate discussion amongst the stakeholders but provides that the third party will not make recommendations to the Commission. The facilitator will provide a report to the Commission summarizing the stakeholders' positions and proposals in the DSP docket.

The objectives of the working group are to:

- exchange information about the technical topics identified in the Settlement Agreement and herein;

[2] Ibid at p. 16.
[3] See Xcel Energy presentation from Working Group Meeting #2.1 at slide #12. (preliminary definition for purpose of demos)
[4] See National Renewable Energy Laboratory, "Advanced Hosting Capacity Analysis," (available at https://www.nrel.gov/solar/market-research-analysis/advanced-hosting-capacity-analysis.html). Additional note - while this definition focuses on integration of DPV, the concept of HCA has extended to other types of distributed energy resources including battery energy storage systems and new load from electric vehicle charging stations.
[5] See Xcel Energy presentation from Working Group Meeting #4.1 at slide #7.
[6] See Workshop #1 presentation from Solar Energy Industries Association (SEIA) at slide #2.

- allow Xcel Energy and stakeholders an opportunity to share draft proposals which may be included in Xcel Energy's 2024 Distribution System Plan and to receive feedback on those proposals to inform future regulatory filings; and
- document all proposals and feedback provided through a report created by an independent facilitator to the Colorado Public Utilities Commission.

The technical working group topics identified in the May 2022 Settlement Agreement included:

- Demand Response Management System ("DRMS") requirements,
- flexible interconnections (including the potential use of energy storage as a possible tool to facilitate interconnection) and smart inverters,
- Distributed Energy Resource ("DER") interconnection issues (including the ability to more timely complete interconnection requests),
- the interaction between Hosting Capacity Analysis ("HCA") and customer data privacy requirements of the 15/15 Rule set forth in Rule 3033,
- unintentional islanding and potential mitigation options for unintentional islanding, and
- the scope and focus of solicitations for third-party pilot proposals.

Relative to bullet point three above, after further discussion between the Company and stakeholders, the participants agreed to address DER interconnection in a separate Commission venue on this topic.

This report aims to provide a summary of:

- technical meetings and attendance / representation at meetings by organization;
- all draft proposals, as well as stakeholder feedback and positions on those proposals; and
- the effectiveness of the facilitated stakeholder process prior to the filing of the Company's next DSP.

TECHNICAL TOPIC MEETING SUMMARIES

The technical working group met 10 times between July 2023 and April 2024 to discuss the five topics identified in the settlement. These meetings started with an opportunity for the group to review the project charter (Meeting 0) and ended with a feedback session on the draft report (Meeting 6). The group comprised 58 individuals representing 26 organizations. All meetings were hosted virtually and were between one and two hours, with some topics broken up into 2-part meetings. A list of meeting attendees is available in Appendix A.

The following section includes summaries from meetings on the five settlement topics.

1. DRMS Requirements / Follow up on Pay for Performance
2. Flexible Interconnection
3. Pilots - Third Party Proposals
4. Unintentional Islanding
5. Hosting Capacity Analysis and 15/15 Updates

1. DRMS Requirements / Follow up on Pay for Performance

Meeting #1 included a presentation (slides #5-20) from Xcel Energy describing their current progress implementing a demonstration project for a Demand Response Management System ("DRMS") and further discussion of a Pay-for-Performance Pilot.

In their presentation Xcel Energy provides:

- An overview of the support its DRMS would provide the Renewable Battery Connect program;
- Consideration of other Distributed Energy Resources (DER) the DRMS may be extended to serve and a discussion of how such extension increases the anticipated DRMS functional requirements ("Evolution of DRMS to Distributed Energy Resource Management System ("DERMS")");
- An update on Xcel Energy's execution of a Request for Information and Request for Proposals to consider and score potential DRMS vendors;
- Further information on Xcel Energy's plans to serve a new Pay for Performance (P4P) pilot with the DRMS system, including the expected characteristics of the P4P pilot and how it may compare to other Colorado DER programs.

Discussion - In response to Xcel Energy's presentation stakeholders requested further information and details in the following areas:

- What additional stakeholders with an interest in Renewable Energy Standard ("RES") Plan (Docket No. 21A-0625EG) Pay for Performance and Renewable Battery Connect should be consulted to inform Xcel Energy's decision-making?
    - Action Item: Group to identify any additional stakeholder outreach needed to add missing perspectives to group and send suggestions to Gridworks.
- Is the scope of the use-cases that would be served by Xcel Energy's proposed DRMS consistent with the settlement?
    - The Technical Working Group discussed how the proposed DRMS would support the Renewable Battery Connect (RBC) and P4P pilot.
    - Xcel Energy is not suggesting they are expanding DRMS capability beyond what they agreed to in the DSP. The settlements require support of RBC and P4P. However, Xcel Energy would like to procure a technology solution that supports these two applications while avoiding procurement of "a dead end" solution. Put differently, the near term goal is supporting RBC and P4P, while keeping in mind an aggregator DERMS to support future programming. One future opportunity is integration with a platform for grid-scale DERMS for community solar.
    - One of the agreements in settlement/decision was about a comprehensive set of goals/metrics tied to the DRMS pilot: where is the company on this front?
        - Company is still planning to set goals and metrics agreed to in the settlement. This Working Group's input will help shape those.
        - Pumping brakes on defining goals/metrics now allows for additional consideration of needed functionality before releasing the forthcoming RFP[7].

[7] See Table One below. Xcel Energy staff indicated that the RFP will be issued imminently.

    - The Technical Working Group discussed the distinction between DRMS and DERMS. In the DSP settlement there was a lot of discussion around this; DERMS was years away and DRMS was a stepping stone pilot to get Xcel Energy to an improved DERMS platform. In implementing the envisioned DRMS solution, it seems the line between these two is unclear.
    - A DERMS system adds additional functionality: Xcel Energy has requested feedback from the TWG on whether spending additional time, and potentially money, to add the functionality is desired.
        - At publish time, Gridworks did not receive TWG input it would consider a clear and definite response to this question posed by Xcel Energy.
        - Action Item: Group to be given an additional opportunity to express a preference at next meeting (September 28, 2024).
- How is the Company vetting vendors and platforms keeping in mind the uncertainty of the future?
    - Xcel Energy shared information through their slides on how vendors are being evaluated. The evaluation includes the expectation that the pilot will need a few summers to test and make adjustments. A partner who can evolve with them will help to 'future proof' the solution.
- How is the Request for Information process unfolding and how will it connect to Xcel Energy's thinking?
    - The RFI went out in June. The company has been reviewing responses. A more formal RFP will follow the review of the RFI, as presented.[8]

Meeting #1 also included a presentation (slides #22-30) by Kevin Lucas from the Solar Energy Industries Association. Mr. Lucas presented an overview of a Virtual Power Plant Concept for stakeholders to consider as a Pay-for-Performance Pilot in fulfilling commitments in two separate but interconnected settlements in the proceedings for the Xcel Colorado's Distribution System Plan (DSP) and Renewable Energy Standard Plan (RES Plan).

Participant Presentation - Mr. Lucas' presentation:

- Introduced the concept of a Virtual Power Plant (VPP) and how they related to rate design;
- Showed examples of how VPPs can alter the inflow/outflow of energy from a customers owned system, shifting load and injecting energy at times that may be advantageous for the grid and the customer; and
- Introduced a potential Colorado VPP policy.

Discussion - After the presentation, the Technical Working Group members discussed the following:

- How a VPP pilot would work when customers already have default Time of Use rates;
    - The merits of focusing on a VPP program relative to dynamic rates that send appropriate price signals;
        - Opening up dynamic rates could open up a whole set of challenges, possibly in the very long term with better technology.
        - VPPs give geographic diversity which allows you to make adjustments in a particular geographic space.

[8] See Meeting 1 slides 9-11 on summary of RFI responses.

    - Not mutually exclusive things to consider. A lot of value in dispatchability construct in VPP.
- The Technical Working Group suggests SEIA's proposal be considered by Xcel Energy as a potential program design for the P4P pilot.

2. *Flexible Interconnection*

Meeting 2.1 Summary:
Meeting #1 Recap - Meeting #2.1 started with a short recap of the prior meeting and asked the working group whether spending additional time and resources on a DERMS was worth the added functionality.

On this topic, several group members shared their perspectives, which included:

- recent experiences from other states;
- Xcel Energy staff further clarified the intended scope of the project as an "Aggregator DERMS";
- multiple stakeholders expressed that the question may be premature; and
- one stakeholder was uncertain how a DERMS could be applicable to flexible interconnection and that multiple features and functions were still being investigated.

As the last discussion item in this section of the meeting, Xcel Energy and COSSA representatives were asked about any updates on the Virtual Power Plant (VPP) conceptual pilot that was presented in Meeting #1. They stated that the Commission had recently opened a proceeding (23M-0466EG) seeking comments around how you might orchestrate a virtual power plant in a vertically integrated market and their immediate attention was focused on responding to the Commission's requests in the opening order. Further, a participant shared this document with the group via email on October 4, 2023.

Xcel Energy Presentation - Xcel Energy staff then made a presentation (slides #8-15) on Flexible Interconnection ("FI") to the working group, which included the following topics:

- Background from DSP Stipulation and Commission's Final Order
- Results and Findings from a Survey send to Technical Working Group members on Flexible Interconnection
- FI Roadmap
- FI Demo Approach Overview

Discussion - After the presentation, Gridworks staff facilitated discussion in three focus areas: FI definition, FI Roadmap, and FI Demo Approach.

Technical Working Group participants had the following comments on the FI definition:

- agree generally with definition but needs to reflect the customer experience;
- needs to acknowledge that customers are creating value and expect to be compensated for curtailment;

- PUC staff testimony in the settlement hearing stated, "flexible interconnect is allowing curtailments, at some level, to obtain an interconnection agreement.[9]";
- compensation for curtailment can be interpreted or directed to other benefits, such as obtaining an interconnection agreement and realizing less interconnection costs or time;
- curtailment (without compensation) is to be avoided; and
- FI also makes larger DER systems possible.

Technical Working Group participants had the following comments on the FI Roadmap:

- Roadmap appears to imply an evolution towards a DERMS and centralized control of DERs, which may be ok for many customers but not all.
    - FI and predefined system limits may be sufficient for certain DER applications without requiring integration into a DERMs.
- Proposed pilot with two locations is a small sample size.
    - if pilots focus on smart inverters, suggest a larger area
    - will provide more detail on pilot recommendations in Meeting #2.2
- Roadmap needs to consider energy storage sooner rather than later.
    - curtailment appears to be main focus of FI currently
    - storage likely to progress over roadmap timeframe, although economics is a challenge
    - Commission's order discussed consideration of energy storage

Technical Working Group participants had the following comments on the FI Demo Approach:

- request a connection between Southwest Power Pool (SPP) market participation and avoiding curtailment; and
- demo objectives should include that FI allows larger systems to interconnect and has value for customers and the utility system.

Meeting 2.2 Summary:
Xcel Energy Presentation (slides #5-10) - Meeting 2.2 started with Xcel Energy presenting a proposal to demonstrate smart inverter functions with larger DER systems (> 1 MW). By agreeing to limit output (curtailment) during constrained periods, demonstration participants could interconnect their DER systems earlier than current rules allow and prior to completing necessary system upgrades. Xcel Energy would analyze the amount of curtailment prior to the demonstration and measure the impact during the project.

Q&A on Xcel Energy's presentation - Stakeholders asked the following clarifying questions on the presentation and proposal:

- Has Xcel Energy reached out to larger DER developers to gauge interest?
    - Xcel Energy staff confirmed they have had preliminary discussions.
- Key information that developers need to know before participating: How much and how often would a project be curtailed? How much would interconnection upgrades cost?
    - Xcel Energy indicated the System Impact Study (SIS) or further studies conducted in the FI demo would provide this information.

[9] See Settlement Hearing Transcript, p. 117 at lines 9-11.

- Later discussion indicated that the best potential candidates are projects waiting on Xcel Energy to conduct major interconnection upgrades. In these cases, the project may be interconnected earlier than original timelines.
    - Xcel Energy believes they have multiple projects that fit this preferred criteria.
- Xcel Energy also noted that certain portions of the interconnection rules (particularly study timelines) may require exemptions/waivers for the demonstration project.

Sunrun Presentation - A representative from Sunrun presented (slides #12-33) a proposal to demonstrate smart inverter functions with residential DER systems, particularly on feeders nearing or exceeding hosting capacity limits for smaller systems. The presentation also discussed hosting capacity analysis and Hawaii's experience with implementing smart inverters.

Q&A on Sunrun's presentation - Stakeholders asked the following clarifying questions on the presentation and proposal:

- A stakeholder asked whether the proposal would address both voltage and thermal impacts. The presenter was optimistic that voltage regulation functions could mitigate thermal impacts and encouraged validating the inverter response and potential indirect thermal impacts through the demonstrations.
- Xcel Energy was asked whether there are residential interconnections triggering interconnection screens on feeders that are serving other larger generators (e.g. community solar)? Xcel Energy confirmed yes. Currently, customers are offered options to enable interconnection on these feeders, which primarily involve limiting exports through pairing with storage.
- Another stakeholder noted that the additional interconnection screens are not limited to feeders with community solar and that additional screening for larger commercial interconnection applications is occurring more broadly.

After clarifying questions on the individual presentations, Gridworks facilitated discussion on both proposals. Stakeholders provided the following feedback:

- Participants seemed optimistic and supportive of Xcel Energy's proposal.
    - Success would be furthered by Xcel Energy providing information to developers necessary to assess and manage risk, especially the following: how much and how often would a project be curtailed? How much would interconnection upgrades cost?
    - Selecting participants from projects that are waiting for Xcel Energy to conduct major interconnection upgrades will substantially help manage developer risk. Questions still remain on the impact of curtailment on project finances.
    - Stakeholder requested Xcel Energy to identify potential partners from their interconnection queue and go in order of the queue. There was agreement on this approach.
- Participants also generally supported Sunrun's proposal especially with its addition of the residential segment.
    - Xcel Energy signaled interest in understanding the proposal in greater detail as well as the examples from Hawaii that were offered to support the proposal.
- Additional discussion points:

- Xcel Energy will need to develop a budget and plan for evaluating the success of a pilot.
- Some stakeholders are interested in the longer-term development of flexible interconnections and potential customer enrollment and contributions to DER under FIs. All agree that the FI demos discussed here are near-term, first step toward that end.

At the end of the meeting, Gridworks conducted a poll to assess the group's satisfaction with the working group process so far.

- 10/12 responded "Very Satisfied"
- 2/12 responded "Satisfied"
- 0/12 responded "Unsatisfied"
- 0/12 responded "Very Unsatisfied"

3. Pilots - Third Party Proposals

Meeting 3.1 Summary:
In Meeting 3.1, Xcel Energy staff presented (slides #6-13) to the working group on: objectives for third-party pilot projects, Xcel Energy's planned areas of interest, overview of proposal process and timeline, and information required for proposals.

During facilitated discussion, stakeholders asked questions on the following topics:

- Updates to proposal process
  - Working group members asked for an official notice and distribution of the solicitation beyond this group.
  - Stakeholders asked questions to clarify budget, including:
    - confirming whether "all-in" cost estimates would be required. Xcel Energy staff stated that proposals would be evaluated on total costs and subject to a project cap.
    - whether the proposer needs to include only their costs or also Xcel Energy's estimated costs. Xcel Energy staff indicated that the initial proposal would need to include only the proposer's cost. However, successful proposals moving forward will work closely with Xcel Energy to develop full project costs, including proposer and utility costs prior to final proposal selection.
  - Xcel Energy's presentation indicated they would provide further information on evaluation criteria and integrate participant feedback on the proposal process in Meeting 3.2.
  - Xcel Energy clarified that parties who submit a concept proposal can work iteratively with the company.
- Stakeholders asked how the third-party pilot process relates to the new M docket on Virtual Power Plants.
  - Could be aligned with what the docket is trying to accomplish..
  - Touches on topics in this group (DERMS, etc.).
  - Some ambiguity remains on how pilots emerging from this working group may relate to VPP Docket. Xcel Energy will take into account other ongoing activities to enable a holistic view and minimize potential overlap.

- Third-Party Pilot timeline
    - Xcel Energy's plans to request additional 3-6 months to submit DSP filing
        - This request would go beyond an unopposed extension from Jan to June 2024.
        - Extension(s) would push back the timeline to file the next DSP to Q3 or Q4 2024.
        - Stakeholders requested that Xcel Energy should update the timeline slide with this new deadline in mind.
- Pilot Areas of Interest
    - Xcel Energy asked if topics were on the right track and no stakeholders expressed opposition.
        - Additional discussion in Meeting 3.2 to allow further review and response.
- Clarity needed on the concept paper and final proposals
    - Stakeholders asked if a concept paper needed to be submitted to be considered for a final proposal. Xcel Energy responded that the concept paper was required.
- Two participating organizations indicated interest in submitting a proposal.
- Suggestion to establish office hours between Xcel Energy and interested parties.

Meeting 3.2 Summary:
In Meeting 3.2, Xcel Energy staff presented (slides #5-10) updates to the initial discussion of Third Party Proposals, which included: review of pilot areas of interest, proposal evaluation criteria, an updated proposal schedule, and Q&A on the proposal process.

During the facilitated discussion, stakeholders provided the following feedback:

- Make Disproportionately Impacted ("DI") communities a criteria; weigh it heavier than other criteria
- Expand solicitation outreach. Additional suggested outreach channels include:
    - An official solicitation system such as https://www.bidnetdirect.com/;
    - City of Boulder offered to share info with the following groups
        - Colorado Municipal League
        - Colorado Communities for Climate Action
    - Notice relevant dockets at CO PUC; and
    - Outreach to Community Based Organizations ("CBOs").
- A stakeholder recommended clarifying that the cost-benefit criteria be focused on the cost-benefit results of the project rather than the clarity of the explanation. Also provided the following feedback:
    - Asked if infrastructure deferral would be a desirable project?
    - Confusion around where to pitch pilots (which docket, proceeding, etc.?). Xcel Energy emphasized that these pilots are a part of the DSP and therefore should primary address distribution system needs and address other areas secondly.
    - Very similar pilot ideas are surfacing in multiple areas, stakeholders are confused as to where their proposals could be best placed.
    - Cost cap and cost treatment - proposer has to have an idea of what Xcel Energy's costs are. Limit proposer's costs to what they can control.
    - If the proposer doesn't know Xcel Energy's costs in time for the final proposal, is it an unworkable arrangement?

        - Xcel Energy responded that they expect to work with proposer during concept proposal phase to estimate Xcel Energy's costs.
- Another stakeholder asked what to expect from office hours between concept proposals and detailed proposals? Xcel Energy staff stated these expectations:
    - 30 minute slots available for 1 week in mid-December 2023[10]; and
    - Proposer would book time slot to ask questions and lead discussion.
- Xcel Energy updated that based on stakeholder feedback from the last meeting, they have added office hour times. A stakeholder asked Xcel Energy if load shift proposals would be eligible. Xcel Energy staff indicated they would but the project needs to address the distribution grid.
    - Xcel Energy also noted this topic (load shift) likely overlaps other pilot areas currently under discussion in Docket No. 23M-0466EG.
- Transmission constraints identified in recent updates to energy resource plans (metro side constraint) - Is this pilot eligible to help address constraint/encourage localized generation?
    - Xcel Energy will review the information filed in a separate docket and get back to stakeholders on this topic.
- Another stakeholder noted that Xcel Energy should share more on the unique opportunities/challenges within DI communities based on their own analysis, which would help prioritize types of projects. Solutions that are broadly applicable might not be relevant in a DI community. For example, EV charging isn't the right load management tool in a DI/industrial blended community. Different needs/strategies within DI communities.
- A stakeholder stated that the Company agreed in the RES plan settlement to work with CBOs on outreach and engagement with DI communities. This is a good place to start. Cities of Denver/Boulder may have some ideas.
- Another noted that the self-selection of participants that is inherent in a technical working group may not lend itself to the type of perspective and participation that you need to develop pilots and programs to serve disadvantaged community needs. Xcel Energy and the working group may need to engage with other parties on this aspect of scoping third-party pilots.

4. Unintentional Islanding

Meeting 4.1 Summary:
Meeting 4.1 started with a presentation (slides #5-21) from Xcel Energy that provided an overview of unintentional islanding (UI) and options available to address UI. Xcel Energy's presentation concluded with further explanation of their current standard practice of installing Voltage Supervisory Reclosing (VSR) on new devices and circumstances that require a retrofit at existing substations.

Mike Ropp presented (slides #23-30) an overview of current industry practices with UI and reported on key lessons from California's UI Working Group that recently concluded.

After the presentations, participants asked questions on the following topics:

- Xcel Energy implementation of VSR:

[10] Xcel Energy staff held office hours after releasing the solicitation in January 2024.

    - A stakeholder asked to clarify when a VSR retrofit is required. What conditions trigger the upgrade and who pays?
        - Xcel Energy explained that a retrofit is required when aggregate nameplate rating of DER downstream of a breaker or recloser exceeds 80% of the minimum applicable load (slide #13 of Xcel Energy presentation).
        - Current practice is for the project/developer that triggers the upgrade is required to pay the cost (estimated at $200k-$400k).
- A stakeholder asked Xcel Energy to provide context on the range of load on feeders and size of projects that would trigger a VSR upgrade.
    - Xcel Energy staff responded that the minimum load varies from 1-4MW (rough rule of thumb). Retrofits would be triggered when reaching 80% of the minimum load on the feeder.
- Mike Ropp was asked to discuss practices in other jurisdictions and current state-of-the-art thinking on UI.
    - The speaker responded that inverter-based response is currently used in some other jurisdictions.
    - Mike indicated that research is currently reviewing area-based communications as a longer-term alternative.
- Xcel Energy asked a question to DER developers on their experience in other jurisdictions.
    - No participants were prepared to respond at the meeting.

Open Questions (addressed as part of Meeting 4.2):

- What fraction of feeders are at or near the criteria requiring a VSR retrofit?
- What percentage of feeders in CO are currently VSR equipped?
- Is this information currently being mapped/displayed for customers/DER developers?
- What alternatives to VSR are used in other jurisdictions?

Meeting 4.2 Summary:
Meeting #4.2 started with a group discussion of the four open unintentional islanding questions from the last meeting. View the presentation slides.

Xcel Energy staff provided the following three responses:

1. What fraction of feeders are at or near the criteria requiring a VSR retrofit? (for Xcel Energy)
    i. Approximately 8% of the Xcel Energy feeders would be at or near the threshold for VSR. This is based on both existing and in queue DER.
2. What percentage of feeders in CO are currently VSR equipped? (for Xcel Energy)
    i. Currently approximately 5% of feeders are VSR equipped with an additional 4% with plans to add VSR capability.
3. Is this information currently being mapped/displayed for customers/DER developers? (for Xcel Energy)
    i. Yes. In general these questions were addressed using existing publicly available information which is posted at https://co.my.xcelenergy.com/s/renewable/developers/interconnection.
    ii. Specifically in the “Before Interconnection” section there is a link to the Hosting Capacity Map

(https://co.my.xcelenergy.com/s/renewable/developers/interconnection/hosting-capacity-map) which besides access the visual map also has linked a spreadsheet summarizing the map information (https://www.xcelenergy.com/staticfiles/xe-responsive/Working%20With%20Us/Renewable%20Developers/2023_Q2_Hosting%20Capacity%20Analysis%20Final%20Feeder%20Report.xlsx). Additionally, within the popup data in the Hosting Capacity Map there is a line item which indicates if a feeder is VSR equipped.

4. What alternatives to VSR are used in other jurisdictions? (for DER industry representatives)
    i. California UI Working Group Final Report
        ii. On the fourth question, Gridworks provided a link to the California Unintentional Islanding Working Group report. There were some stakeholder questions noting that VSR was not among the options California utilities considered.

In the remainder of time, meeting participants then responded to discussion questions concerning unintentional islanding:

1. What is working well with the current practice?
    a. Participants had limited feedback on this topic (summarized in 3d and 3g below).
2. What could improve with the current practice?
    a. Participants reiterated that current practice to allocate full costs of mitigation is a challenge for the DER projects that trigger the VSR upgrade for the feeder.
3. Which alternatives could improve current practice?
    a. On this question, some stakeholders discussed alternative mitigation options at the point of interconnection for DER projects. (In meeting 4.1, Mike Ropp discussed alternative mitigation options and emerging best-practices in other jurisdictions - see above summary of that discussion.)
    b. Xcel Energy staff provided initial feedback that the project-specific alternatives did not provide the same level of certainty in maintaining reliability as the current standard.
    c. At this point, facilitators presented options to summarize the discussion and offer possible next steps for further dialogue on this topic.
    d. Participants did not feel prepared to accept or reject Xcel Energy's VSR recommendation at this time.
    e. One stakeholder offered to survey members on preferred alternatives to VSR and get back to the group ASAP.
    f. Gridworks offered to follow up with stakeholder on this to fix a timeline for completing that process and has sent initial emails to follow up. (See Meeting 5 notes for further discussion)
    g. Another stakeholder suggested parties need help evaluating the options from a neutral, technically focused organization like EPRI.

5. Hosting Capacity Analysis and 15/15 Updates

Meeting 5 Summary:

Meeting #5 started with a presentation (slides #5-10) from Xcel Energy that discussed the role of hosting capacity analysis (HCA) within the interconnection process and Xcel Energy's near-term plans to upgrade distribution modeling software and automate parts of their HCA ("roadmap").

The improvements in the roadmap include:

- developing "unblurred" HCA maps with greater detail on Xcel Energy's distribution system (May 2024 Update - Unblurred HCA maps are now available);
    - users need to sign non-disclosure agreement (NDA) to access detailed maps
- providing tabular results for Load HCA; and
- automating HCA processes to update maps more frequently;
    - starting with quarterly and moving to monthly updates .

After the presentation, working group members asked clarifying questions in the following areas:

- If planned upgrades for Public Service Company of Colorado would be available in other Xcel Energy service territories (Minnesota, Wisconsin).
    - Xcel Energy representative said upgrades would be available in Colorado first but Minnesota PUC is currently considering physical and cyber security risks and protections related to data sharing for HCA data and maps.
- A stakeholder asked to clarify the timeline for access to the unblurred maps.
    - Xcel Energy staff indicated the maps would be available through the web portal after the "go live" date.
- Xcel Energy was asked further questions on the automation process and why updates to the HCA could not occur continuously.
    - Xcel Energy staff responded that the upgrades automate parts of the process but not all steps. Quality Assurance would remain primarily a manual process.
- A stakeholder asked if load HCA information would be mapped similar to generation data.
    - Xcel Energy staff stated they are reviewing the system security implications of providing the load information but the capability to map the information currently exists.
- Another stakeholder asked how load forecasting information developed in the LoadSEER model is integrated with the distribution system modeling software (CYME).
    - Xcel Energy staff explained that the roadmap anticipates directly linking load forecast outputs from the LoadSEER model into CYME. This linkage would provide more granular analysis of distribution system load flows.s.

Working group members expressed general support for the planned improvements in the following areas:

- Increased detail in the unblurred HCA maps
- Automated process
- Transition to monthly reporting
- Providing granular data on Load HCA
- Transition to mapping Load HCA

Working group members also indicated the following areas for future improvements:

- Time-of-day data when feeder reaches peak demand
- Quicker transition to mapping Load HCA will start with tabular data
- Opportunities to better understand grid needs from HCA maps

Unintentional islanding wrap up:

- No future updates or comments from group
- Two working group members (AEU and COSSA) went back to membership/colleagues and did not receive responses

After the working group meeting via email, a stakeholder requested further technical reports on unintentional islanding, particularly any studies that were available to Xcel Energy through the Electric Power Research Institute (EPRI).

Xcel Energy staff responded with further explanation of the material presentation by Mike Ropp in Meeting 4.1, provided a list of the EPRI reports (noting which are public or available for purchase), and summarized Xcel Energy staff's review of EPRI's research on the topic.

Gridworks will schedule a portion of the final meeting to discuss any further feedback on this topic.

REFLECTIONS

Gridworks has two main reflections after facilitating the technical working group. First, the group met the work plan objectives that participants agreed to at the start of the process. A short summary of the group's progress on each objective is listed below. Second, working group members committed a significant level of time and expertise to participate in all of the meetings. While meeting the objectives in the work plan, there is potential for greater impact in convening this group of experts. Gridworks offers suggestions below that could enhance the impact of future technical working groups.

Progress on Technical Working Group's Objectives

- *Objective #1 - exchange information about the technical topics identified in the work plan* - The technical working group held eight meetings on the five topics identified in the work plan. For each meeting, Xcel Energy staff provided a significant level of support in planning the meeting and had the relevant subject matter experts attend all meetings. Prior to each meeting Xcel Energy provided the presentations to Gridworks in advance of each stakeholder meeting. Gridworks provided the agenda and presentation three days prior to each scheduled meeting. The Xcel Energy subject matter experts discussed and responded to stakeholder questions during working group meetings. Where necessary, Xcel Energy staff promptly provided requested information after meetings. Stakeholders contributed to the discussions on each topic by offering constructive feedback on Xcel Energy's proposals. On some topics, stakeholders also proposed alternative concepts. The meeting summaries included above document the discussions in each meeting. From

review of these summaries, the working group did succeed in exchanging information on the technical topics in the work plan.

- *Objective #2 - allow Xcel Energy and stakeholders an opportunity to share draft proposals which may be included in Xcel Energy's 2024 Distribution System Plan and to receive feedback on those proposals to inform future regulatory filings* - On each topic, both Xcel Energy and stakeholders were provided opportunities to share draft proposals and offer/receive feedback. For reference, Table One summarizes the proposals on each topic and current status provided by Xcel Energy staff.

Table 1 - Summary of Proposals reviewed by Technical Working Group

Topic	Xcel Energy Proposal	Stakeholder Proposal(s)	Current Status
1. DRMS/Pay for Performance	Xcel Energy will issue RFP for DRMS/DERMs; proposed pilots to support Renewable Battery Connect and pay-for-performance concept.	SEIA representative presented on virtual power plant pilot	RFP for DRMS/DERMs will be released imminently. Discussions on pay-for-performance pending in legislature and PUC M docket. Xcel Energy next steps will be informed by discussions in these venues.
2. Flexible Interconnection	Pilot flexible interconnection with 2 community solar projects (> 1 MW)	SunRun presented on smart inverter pilot concepts	Demonstration scope is on track. Xcel Energy has a workstream for both large and small solar projects.
3. Third-party Pilots	Xcel Energy presented solicitation framework	Stakeholders provided feedback	Solicitation opened in January 2024. The Company received approximately 30 submissions and has shortlisted a handful of proposals for full proposal submission.
4. Unintentional islanding	Xcel Energy discussed current	Gridworks invited presentation from	Technical working group discussed Xcel

	standard and technical requirements	Sandia National Labs expert (Mike Ropp) on California Unintentional Islanding Working Group	Energy's current approach and stakeholder concerns. No working group consensus achieved on an alternative.
5. Hosting Capacity Analysis	Xcel Energy presented roadmap for HCA improvements	Stakeholders provided feedback on roadmap	Xcel Energy received generally supportive feedback on roadmap

- *Objective #3 - document all proposals and feedback provided through a report created by an independent facilitator to the Colorado Public Utilities Commission* - This final report compiles the meeting summaries that document the proposals on each topic and discussion during working group meetings.

Enhancing Impact of Future Technical Working Groups

Gridworks observed that the level of stakeholder participation declined over time as organizational priorities and ability of stakeholders to participate fully changed during the series of meetings. This is understandable given the length of time from the settlement agreement recommending the working group (November 2022) and convening of the discussions from August 2023 - February 2024.

This working group required a substantial time commitment from stakeholders to prepare and participate in all of the meetings. Gridworks suggests some additional options to enhance the impact of future technical working groups:

Periodic reporting to the CO PUC while the working group is convening - By periodically updating the Commission on the group's progress, the Commission will remain informed on the discussions and can offer any direct feedback for group members. The next working group can decide on an appropriate format to make these reports to the Commission.

Include stakeholder review process prior to filing Xcel Energy's next DSP - Review and stakeholder feedback on the utility's next filing may provide the most value from the expertise of participants. The group's work scope could also involve fewer meetings and greater focus on the upcoming filing with the Commission. This more limited commitment may better align with the time available from stakeholders and encourage participation by a broader set of stakeholders.

APPENDIX A: MEETING ATTENDANCE

Table A1 - List of working group organizations with the number of representatives that attended each meeting.

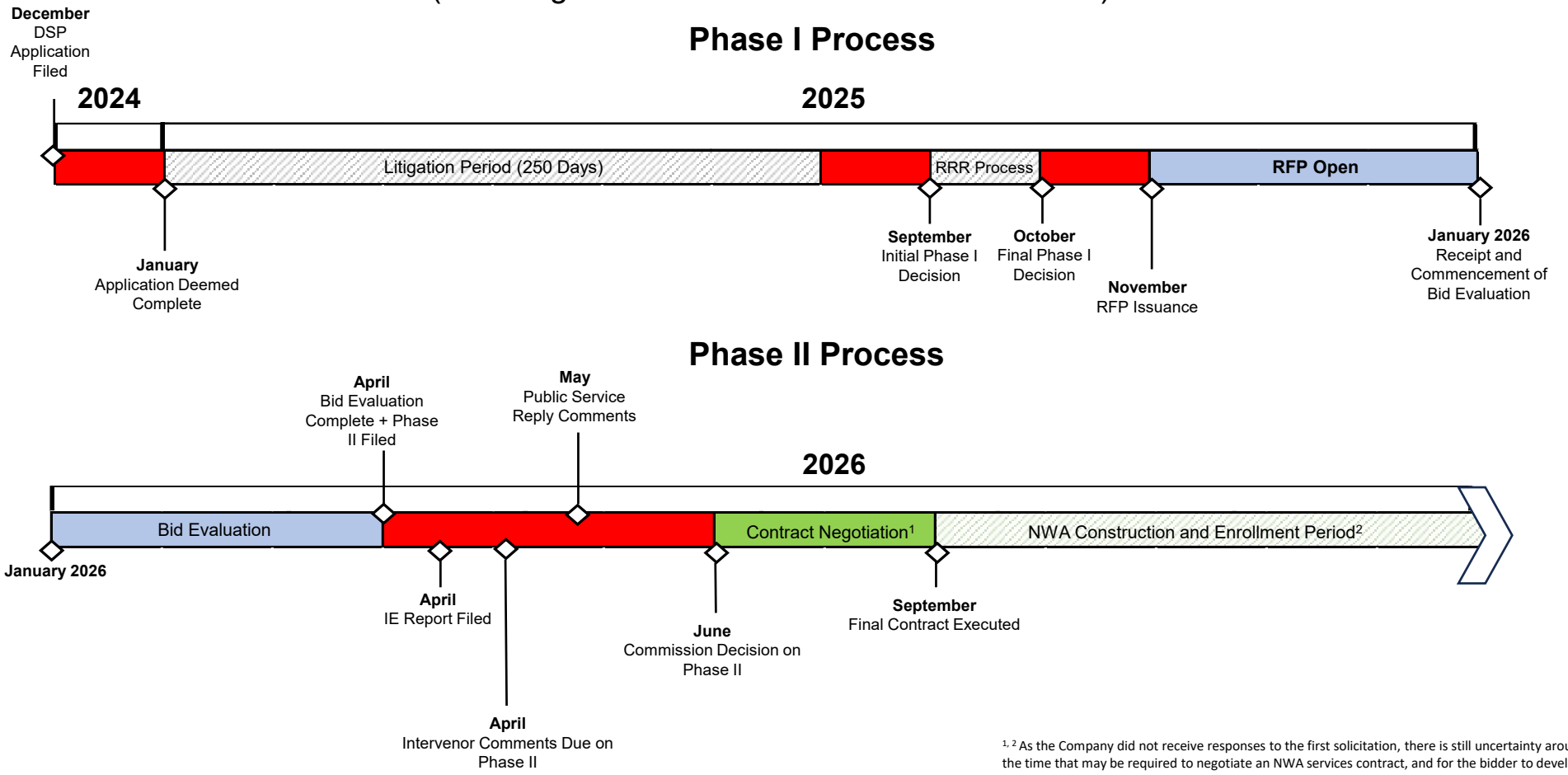
Organization	Mtg 0	Mtg 1	Mtg 2.1	Mtg 2.2	Mtg 3.1	Mtg 3.2	Mtg 4.1	Mtg 4.2	Mtg 5	Mtg 6
Advanced Energy United (AEU)	1	1	1		1	1	1	1	1	1
Buglet Solar Electric										
City and County of Denver	1	1	1	1			1	2	1	1
City of Boulder	2	4	2	2	2	2	3	1	1	1
Cloudbreak Energy	1		1							
CO Utility Consumer Advocate										1
Colorado Energy Consumers (CEC)			1							
Colorado Energy Office (CEO)	1		1		1	1	1	1	1	1
Colorado Public Utilities Commission	2	6	3	3	1	3	1	1	2	1
Colorado Solar and Storage Association (COSSA)	1	2	2	2		1				
Electric Power Research Institute (EPRI)		1	2	1	1	1		1	1	
Gridworks	3	3	3	3	3	3	4	2	3	3
Guidehouse		1								
ICF										
Independent Consultant	1		1	1	1	1			2	1
McKinstry	1		1				1	1	1	
Namaste Solar									1	
National Renewable Energy Laboratory (NREL)		2								

Pacific Northwest National Laboratory			3	3						
Pivot Energy			1						1	
Sunnova		2								
Sunrun		1	2	2						
SunShare			1							
SWEEP	1	1	1		1					1
Tesla										
Visa		1								
Vote Solar	1				1					
Western Resource Advocates (WRA)	2	1	1	2		2	2	1		
Xcel Energy	8	11	11	9	8	8	8	8	8	5
Total Attendees*	26	38	39	29	20	23	22	19	23	16

* Total includes technical working group members, Colorado Public Utilities Commission staff, Gridworks staff (independent facilitator), and Xcel Energy staff (utility). Count does not include additional participants from the public that attended each meeting.

Appendix 8 - Phase I and Phase II Timeline

Public Service Company of Colorado's Proposed Timeline for the Phase I and Phase II DSP Process
(including solicitation of Non-Wires Alternatives)



[1, 2] As the Company did not receive responses to the first solicitation, there is still uncertainty around the time that may be required to negotiate an NWA services contract, and for the bidder to develop their respective NWA(s)