Decision No. C25-0903

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 24A-0547E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF ITS 2025-2029 DISTRIBUTION SYSTEM PLAN AND THE GRID MODERNIZATION ADJUSTMENT CLAUSE.

PROCEEDING NO. 25A-0061E

IN THE MATTER OF THE APPLICATION FOR APPROVAL OF PUBLIC SERVICE COMPANY OF COLORADO'S AGGREGATOR VIRTUAL POWER PLANT PROGRAM AND TARIFF, ALONG WITH ASSOCIATED PROGRAM BUDGET AND COST RECOVERY METHODOLOGY.

COMMISSION DECISION GRANTING APPLICATIONS WITH MODIFICATIONS, REQUIRING FILINGS, ADDRESSING MOTIONS, AND ISSUING CERTAIN DIRECTIVES TO GUIDE FUTURE FILINGS

Issued Date: December 15, 2025
Adopted Date: October 23, 2025, October 29, 2025, October 30, 2025, November 5, 2025, November 19, 2025, and December 10, 2025

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I. BY THE COMMISSION

A. Statement

1. On December 16, 2024, Public Service Company of Colorado ("Public Service" or the "Company") filed its Application for Approval of its 2025-2029 Distribution System Plan ("DSP") and Grid Modernization Adjustment Clause ("DSP Application") in this Proceeding. On January 31, 2025, pursuant to Senate Bill ("SB") 24-218, Public Service filed an Application for Approval of an Aggregator Virtual Power Plant in Proceeding No. 25A-0061E (Proceeding No. 25A-0061E or "AVPP Application"). This Proceeding is the consolidated docket of the AVPP Application and the DSP Application.

2. Based on the record established in this Proceeding, we grant, with additional modifications, the Company's AVPP Application and the Company's DSP Application, both as

modified by the settlements filed in this Proceeding. We also authorize the establishment of the Grid Modernization Adjustment Clause ("GMAC") as discussed further herein.

B. Procedural History

3. On December 16, 2024, Public Service filed its DSP Application with supporting testimony and associated attachments of eight witnesses. Concurrent with its DSP Application, the Company filed an Omnibus Motion for Extraordinary Protection of Highly Confidential Information and for a Partial Variance from Rules 3528(c) and 3527(b)(VI) ("Omnibus Motion"). The Commission addressed the requests for extraordinary protection found in the Omnibus Motion through Decision No. C25-0259-I, issued on April 7, 2025.

4. Through Decision No. C25-0057, the Commission found that more information was necessary before deeming the DSP Application complete, and required Public Service to file responsive information by February 14, 2025. Public Service timely filed the requested information on February 14, 2025, as Hearing Exhibit 109 and associated attachments.

5. On January 31, 2025, Public Service filed its AVPP Application with supporting testimony and associated attachments of three witnesses.

6. By Decision No. C25-0085-I, issued on February 6, 2025, in the AVPP Proceeding, the Commission noted the Company's AVPP Application may have overlapping factors and interrelated impacts with its DSP proceeding and requested comment from potential parties to the AVPP Proceeding regarding the potential advantages and disadvantages to combining the AVPP and DSP proceedings.

7. By Decision No. C25-0154-I, issued on March 4, 2025 in the DSP Application Proceeding, the Commission deemed the DSP Application complete and granted the requests for permissive intervention filed by Colorado Energy Consumers Group ("CEC"); the City and

County of Denver ("Denver"); the Interstate Renewable Energy Council ("IREC"); Pivot Energy Inc. ("Pivot"); the Eastern Metro Area Business Coalition (the "Eastern Metro Area Business Coalition"); the City of Boulder ("Boulder"); Holy Cross Electric Association Inc. ("Holy Cross"); Western Resource Advocates ("WRA"); Tesla, Inc. ("Tesla"); the Southwest Energy Efficiency Project and Natural Resource Defense Counsel, jointly ("SWEEP/NRDC"); Mission:data Coalition, Inc. ("Mission:data"); and filing jointly, the Colorado Solar and Storage Association ("COSSA"), the Solar Energy Industries Association ("SEIA"); the Coalition for Community Solar Access ("CCSA"), and the Advanced Energy United ("AEU") (jointly the "Associations for Clean Energy," or "ACE"). The Commission acknowledged the notices of intervention of right filed by Trial Staff of the Commission ("Staff"), the Office of the Utility Consumer Advocate ("UCA"), and the Colorado Energy Office ("CEO").

8. Also through Decision No. C25-0154-I, the Commission ordered the Company to file certain information through supplemental direct. Public Service timely filed some of the requested information on March 21, 2025, as Hearing Exhibits 110 - 113 and associated attachments. On March 12, 2025, Public Service filed a Motion for Partial Variance from Commission Decision No. C25-0154-I in which it requested a modification to certain supplemental direct directives. The Commission addressed this motion in Decision No. C25-0202-I and Decision No. C25-0260-I. On May 19, 2025, Public Service filed second supplemental direct testimony as Hearing Exhibit 114 and associated attachments.

9. By Decision No. C25-0155-I, issued on March 5, 2025 in the AVPP proceeding, the Commission deemed the AVPP Application complete and established the parties to the AVPP proceeding, including: CEC; Pivot; Boulder; WRA; AEU; COSSA/SEIA/CCSA; Colorado Renewable Energy Society ("CRES"); William Althouse ("Mr. Althouse"); Solar United

Neighbors ("SUN"); CEO; UCA; and Staff. Also through Decision No. C25-0155-I, the Commission ordered the Company to file certain information through supplemental direct. Public Service timely filed the requested information on March 21, 2025, as Hearing Exhibit 104 and associated attachments in the AVPP proceeding.

10. By Decision No. C25-0261-I, issued in each the DSP and AVPP proceedings, the Commission consolidated the DSP and AVPP Applications and established a procedural schedule for the consolidated proceeding (hereafter any reference to "this Proceeding" refers to the consolidated DSP and AVPP proceedings). The consolidated proceeding was given 24A-0547E as the main proceeding designation.[1] The parties to the consolidated proceeding are: Staff; CEO; UCA; CEC; Denver; IREC; Pivot; Eastern Metro Area Business Coalition; Boulder; Holy Cross; WRA; Tesla; SWEEP/NRDC; Mission:data; COSSA/SEIA/CCSA;[2] AEU; CRES; Mr. William Althouse; and SUN.

11. On March 13, 2025, the Commission held a technical conference scheduled by Decision No. C25-0154-I. This technical conference addressed parallel forecasting efforts the DSP Proceeding and in Public Service's 2024 Just Transition Solicitation ("JTS Proceeding").[3]

12. On or around June 26, 2025, the Commission received answer testimony from: CRES; Denver; Tesla; Eastern Metro Business Coalition; Mission:data; ACE; SWEEP/NRDC; WRA; CEO; UCA; Staff; Mr. Althouse; IREC; ACE; Boulder; and AEU.

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[1] To ensure a clear administrative record, the Company refiled all direct and supplemental direct testimony in the AVPP proceeding into the DSP Proceeding. Therefore, hearing exhibits 115-119 and associated attachments in the DSP Proceeding are the AVPP Application original materials and supplemental direct.

[2] Originally, COSSA/SEIA, CCSA, and AEU intervened in the DSP Proceeding as the "Associations for Clean Energy." COSSA/SEIA/CCSA retained the moniker "Associations for Clean Energy" after the DSP and AVPP proceedings were consolidated. Hereafter, any reference to "Associations for Clean Energy" or "ACE" does not include AEU.

[3] Proceeding No. 24A-0442E.

13. On or around July 23, 2025, the Commission received rebuttal testimony from the Company, and cross answer testimony from AEU; Mission:data; SUN; Denver; SWEEP/NRDC; WRA; Tesla; Eastern Metro Business Coalition; CEO; UCA; ACE; Boulder; and Mr. Althouse.

14. On July 28, 2025, Mission:data filed a motion requesting the Commission order penalties against Public Service pursuant to § 40-7-105, C.R.S. ("Penalty Motion").

15. On August 15, 2025, the Company filed a Motion to Approve Comprehensive AVPP Settlement Agreement, Motion to Approve Unopposed NWA-TDA Settlement Agreement, Notice of Partial GMAC Stipulation, Unopposed Motion for Variance of Settlement Testimony Deadline, and Unopposed Request to Shorten Response Time ("Settlement Motion").[4] The Company also filed three settlement or stipulations. The first is a stipulation addressing GMAC, filed by the Company on behalf of Boulder; Eastern Metro Area Business Coalition; ACE; SWEEP/NRDC; AEU as Hearing Exhibit 133 ("GMAC Stipulation"). The second is a settlement agreement addressing non-wires alternatives and targeted demand areas issues filed by the Company on behalf of UCA, CEO, Boulder, WRA, ACE, CRES, SWEEP/NRDC, filed as Hearing Exhibit 132 ("NWA/TDA Settlement"). Finally, the Company filed a settlement agreement intended to resolve all issues in the AVPP proceeding on behalf of Staff; Boulder; WRA; AEU; ACE; CRES; SUN; and Tesla, filed as Hearing Exhibit 131 ("AVPP Settlement").

16. On August 15, 2025, the Company also filed Settlement Testimony as Hearing Exhibit 134. On or around August 18, 2025, Staff filed Settlement Testimony as Hearing Exhibit 506; Boulder filed Settlement Testimony as Hearing Exhibit 1104; UCA filed Settlement Testimony as Hearing Exhibit 607; AEU filed Settlement Testimony as Hearing Exhibit 2104; SUN filed Settlement Testimony as Hearing Exhibit 2001; and WRA filed

[4] The Company filed a revised version of the Settlement Motion on August 18, 2025.

Settlement Testimony as Hearing Exhibit 1704, Mr. Althouse also made a filing indicating his opposition to the AVPP Settlement.

17. On August 21, 2025, the Commission held a pre-hearing conference, scheduled by Decision No. C25-0577-I, to discuss efficiencies that could be achieved at the evidentiary hearing.

18. On August 25-29, 2025 and September 2-3, 2025, the Commission convened an evidentiary hearing, during which parties had opportunity for cross examination and the Commissioners questioned certain witnesses. In addition, the Commission admitted Hearing Exhibit 2300 and all of the documents listed thereon into evidence. This document consists of all of the pre-filed testimony and attachments in the Proceeding. In addition, during the course of the hearing, the following hearing exhibits were offered and admitted into the record: Hearing Exhibits 107, Rev. 1 (confidential and public versions); 136; 138; 140; 141 (confidential and public versions); 143; 147; 148 (corrected version); 157; 404; 409; 544; 905; 607 and associated attachments; 610; 803C; 805; 810; 904HC; 912; 914; 915; 916; 917; 919; 1103; 1104; 1105; 1106; 1107; 1109; 1110; 1502; 1505; 1506; 1507; 1508; and 1509. The Commission also administratively noticed hearing exhibits 142; 405; 406; 906; 907; and 1108.

19. On August 26, 2025, the Commission held a public comment hearing at which approximately 40 members of the public shared oral comments with the Commission.

20. On September 26, 2025, Public Service, Staff, Mr. Althouse, UCA, Tesla,[5] AEU, CEC, SUN, SWEEP/NRDC, ACE, Eastern Metro Business Coalition, WRA, CEO, Mission:data, Denver, IREC, and Boulder each filed a statement of position ("SOP").

[5] On September 30, 2025, Tesla filed a Motion for Variance to file a revised SOP. By this Decision, we grant the Motion for Variance filed by Tesla, and we considered the revised SOP for these deliberations.

21. The Commission held a technical conference on December 3, 2025, in which the Company explained its filing regarding the revenue requirement for the GMAC, calculated consistent with the Commission's oral deliberations.

22. The Commission conducted live deliberations in this Proceeding at the Commissioners' Weekly Meetings on October 29, 2025, November 5, 2025, and December 10, 2025, at Commissioners' Deliberations Meetings on October 23, 2025, October 30, 2025, and November 19, 2025, resulting in this Decision.

C. Background and Statutory Requirements

23. The filing requirements for this Proceeding come from numerous sources, including the Commission's DSP Rules, the settlement approved in the Company's inaugural DSP proceeding,[6] and recently enacted statutory provisions, including SB 24-218 and SB 24-207.

24. The Commission originally instituted the DSP Rules (4 *Code of Colorado Regulations* ("CCR") 723-3-3500 *et seq*.,) in Proceeding No. 20R-0516E. The Commission's DSP Rules require utilities with over 500,000 customers to file a DSP as an application every two years.

25. Pursuant to the Commission's Rules, a DSP shall contain:

- a description of the objectives of the DSP, including the utility's ten-year vision for distribution grid capabilities and services that meet customer needs and state policy goals;
- a description of how the distribution grid may evolve over the next five and ten years due to various factors;
- a description of the utility's vision of how existing utility demand-side management measures and programs, as well as other existing distributed energy resource offerings, shall or could be utilized or modified to meet distribution system planning needs;
- distribution system forecasts, as described in rule 3530;

[6] *See* Decision No. R23-0080, issued on February 2, 2023, in Proceeding No. 22A-0189E.

- an assessment of the existing distribution system, as described in rule 3531;
- an assessment of grid needs, as described in rule 3532;
- a description of grid innovations and any proposed pilots and programs, as described in rule 3533;
- Non-wire Alternative ("NWA") suitability screening results, as described in rule 3534;
- a proposed NWA cost benefit analysis methodology, as described in rule 3535;
- any proposed documents and model contracts that the utility intends to use for NWA solicitation or procurement;
- a Phase I action plan, as described in rule 3536;
- a proposal for cost recovery, which may include an incentive, as described in rule 3538;
- a security assessment, as described in rule 3539;
- a proposal for implementation of a web portal as described in paragraph 3541(d);
- a description of the stakeholder engagement process, as described in paragraph 3528(g); and
- a description of how the utility has engaged, and plans to engage, on DSP with communities, particularly disproportionately impacted communities, and how the utility has incorporated community climate, equity and resilience goals and priorities into the DSP and action plan.

26. Consistent with the Commission's DSP Rules, the Commission shall issue written decisions approving, conditioning, modifying, or rejecting the utility's DSP filing. The Commission may modify any plan, as appropriate, to optimize overall system costs and ratepayer benefits, to improve services derived from the distribution grid, and to achieve state policy goals pursuant to Rule 3526. These decisions create a presumption that utility actions consistent with the decisions are prudent.[7]

[7] Commission Rule 4 CCR 723-3-3538(e).

27. The Company filed its first DSP pursuant to the Commission's DSP Rules in Proceeding No. 22A-0189E. That proceeding resulted in a settlement approved by Decision No. R23-0080 ("2022 DSP Settlement Agreement").

28. In 2024, the Legislature passed the SB 24-218, concerning "Measures to Modernize Energy Distribution Systems," codified at § 40-2-132.5, C.R.S. SB 24-218 requires several short-term and long-term actions by the Commission and Public Service. Notably, the legislation requires the utility's a DSP to create "sufficient hosting capacity across its electrical distribution system to affordably and reliably support the implementation" of the following: (I) Federal, state, regional, and local air quality and decarbonization targets, standards, plans, and regulations; (II) The transportation, affordable housing, new infill housing, and building electrification policies of state and local law []; (III) State agency, local agency, and local government plans and requirements related to housing, economic development, critical facilities, transportation, and building electrification; (IV) Enforceable and funded federal, state, regional, and local policies, plans, goals, incentives, or requirements designed to increase access to distributed energy resources, electrified transportation, and building electrification in disproportionately impacted communities; and (V) The qualifying retail utility's approved renewable energy standard plan, clean heat plan, beneficial electrification plan, demand-side management plan, gas infrastructure plan, and transportation electrification plan. § 40-2-132.5(5)(a), C.R.S.

29. Senate Bill 24-218 also adds additional filing requirements in addition to the Commission's DSP Rule requirements. Public Service's DSP shall also include the presentation of:

- at least two future planning scenarios with corresponding investments to show different future states of the distribution system pursuant to the requirements in § 40-2-132.5(5)(c), C.R.S.;

- a performance-based framework pursuant to the requirements in § 40-2-132.5(5)(e), C.R.S.; and
- an analysis of its current qualified staffing level and future required qualified staffing level for each job classification needed to achieve the policies and requirements of the legislation pursuant to the requirements in § 40-2-132.5(5)(f), C.R.S.

30. SB 24-218 requires the Commission to evaluate whether the utility's DSP: (I) Establishes a long-term distribution system plan, which must cover at least five years, that includes timelines and budgets to create sufficient hosting capacity across the qualifying retail utility's electrical distribution system to affordably and reliably support the implementation of the applicable targets, standards, plans, and regulations described in subsection (5)(a); (II) Includes the identification of specific distribution investments needed to strategically support the applicable targets, standards, plans, and regulations described in subsection (5)(a) over the planning period…; (III) Includes detailed mapping of distribution hosting capacity with appropriate safeguards to protect critical infrastructure…; (IV) Includes a process to identify and evaluate infill housing loads; (V) Includes proposed, unless already informed or satisfied by commission rules, standardized, quantifiable, and transparent processes and timelines within the planning period for formal load and generation interconnection and energization requests…; (VI) Includes proposed actions to facilitate programs for: (A) The competitive acquisition of cost-effective non-wires alternatives to defer or avoid identified system distribution infrastructure projects, subject to investment thresholds in commission rules; (B) Load and generation flexibility, including interruptible programs, with due consideration given to programs proposed or approved in other commission proceedings; and (C) Other alternatives to system upgrades, which may include automated distributed resource management systems; (VII) Includes adequate reporting and system mapping to implement the proposed plan and programs…; and (VIII) Includes

documentation demonstrating progress toward implementation of previously approved distribution system plans.

31. SB 24-218 also includes filing requirements related to an application to implement a virtual power plant program, including a tariff for performance-based compensation to support a qualified virtual power plan. SB 24-218 defines a virtual power plant as a "program that achieves the collective management of dispatchable demand or distributed energy resources connected to the utility distribution grid." Section 40-2-132.5(8), C.R.S., includes the filing requirements for the program. Additionally, SB 24-218 requires the Commission to establish a grid modernization adjustment clause ("GMAC") in a utility's first distribution system plan application after May 22, 2024. Within the distribution system plan, a qualifying retail utility shall propose, and the Commission shall evaluate, whether the projected distribution activities and corresponding budgets strategically benefit or advance the applicable targets, standards, plans, and regulations described in subsection § 40-2-132.5(5)(a), C.R.S., or state energy policy goals, including greenhouse gas emission reductions, beneficial electrification, increased reliability, and increased resiliency, and the Commission shall allow grid modernization adjustment clause recovery for such approved distribution activities.

32. This consolidated Proceeding comprises the AVPP Application and the DSP Application filed by Public Service. Public Service filed its DSP Application pursuant to § 40-2-132.5, C.R.S., and Commission Electric Rules 4 CCR 723-3-3529 to 3541. In the DSP Application, the Company requests approval of its 2025-2029 DSP as well as its proposed GMAC rider. In its Application, the Company requests, at a high-level, several approvals, including: (1) Approval of the GMAC framework, including the Type 1 and Type 2 GMAC categorizations, and the GMAC performance screen approach; (2) Authorization to commence the GMAC and

approval of the associated GMAC tariff; (3) Approval of the Company NWA proposals and approach to evaluation; (4) Approval to implement any tariff revisions that may become necessary to allow undergrounding-related efforts in non-franchised areas; (5) Authorization of deferred accounting treatment for expenses that have been incurred or are expected to be incurred as related to this DSP, at no return, to be brought forward for review and recovery in a future Phase I electric rate case; (6) The variances requested by separate motion to allow for implementation of the Plan with respect to the timing of the Phase II NWA solicitation process; and (7) Any other relief necessary to implement the DSP.

33. Public Service filed its AVPP Application pursuant to § 40-2-132.5, C.R.S., which requires Public Service to file by February 1, 2025, an application to implement a virtual power plant ("AVPP") program, including a tariff for performance-based compensation for a qualified AVPP. The Company is required, among other things, to consider the role that AVPPs can play in modeling and meeting system needs in the resource planning process and eligibility requirements for distributed energy resource ("DER") aggregators and technologies. The Company must also establish requirements for DER aggregators including communication, dispatch, measurement and verification, and settlement of performance-based compensation.

D. 2025-2029 Distribution System Plan Components

1. Capacity Planning

a. Background/Company Approach

34. Pursuant to the Commission's DSP Rules, a utility shall include a distribution system forecast consistent with Rule 4 CCR 723-3-3530. The demand forecasts shall be prepared for each year within the ten-year planning period, should be based on at least two growth scenarios (state policy and high), and should include reasonably detailed predictions of the expected

geographic areas of substantial growth within the distribution substation grid area and impacts on planning for the transmission and distribution system, including impacts due to DER adoption and increased demand flexibility and demand response within the utility's service territory. The utility shall forecast growth, including peak load growth at each substation, substation transformer, and feeder, by year, and shall consider the impacts of various factors, including anticipated new neighborhood or housing development growth, impacts of DER and demand-side management ("DSM"), demand response ("DR"), and demand flexibility, and other factors.

35. Pursuant to § 40-2-132.5(5)(c)(I), C.R.S., the utility shall present at least two future planning scenarios with corresponding investments to show different future states of the distribution system. A utility shall also provide a scenario that incorporates load and managed generation flexibility that may increase system capacity utilization, reduce the need for system upgrades, and lower system costs.[8] In determining which portions of the distribution system to propose system upgrades, a utility shall prioritize capacity investments in areas of its distribution system that are at or near their hosting capacity limits or that are projected to have energization loads that cannot be met without a system upgrade. A utility shall also prioritize system upgrades targeted at improving infrastructure for income-qualified or disproportionately impacted communities with residential capacity constraints.

36. The DSP Rules also require the utility to present an assessment of its existing distribution system, as described in Rule 4 CCR 723-3-3531 and the existing distribution system assessment shall include a hosting capacity analysis.

[8] § 40-2-132.5(5)(c)(II), C.R.S.

37. The Company employed two modeling exercises: 1) the LoadSEER model it runs internally;[9] and 2) a longer-term "Grid of the Future" planning exercise conducted by consultant Kevala.[10] Both forecasting efforts are geographically distinguished by 13 distinct planning divisions.[11]

38. The Company explains that an array of end-use loads and resources require a more robust distribution grid, including currently: 100,000 solar PV systems; 100,000 electric vehicles ("EV") (up from 20,000 only five years ago, and aiming to achieve 400,000-500,000 EVs by 2030 per State-wide goals); a burgeoning market for air-source heat pumps (growing from "single-digit thousands today but may need to grow to hundreds of thousands of installations by 2030 to achieve Colorado's clean heat goals"); and distributed storage installations that also may grow significantly as it has in other markets.[12] Overall, the Company projects it will shift from a summer-peaking utility to a winter-peaking utility by approximately 2032, and that peak load will grow rapidly from around 6,500 MW currently to over 12,000 MW in the next couple of decades.[13]

39. The Company's forecasting process begins with determining base load by using data from individual system components as collected through a Supervisory Control and Data Acquisition ("SCADA") system. Through the LoadSEER model, planners "scrub" three years of historical SCADA data for each asset to remove data errors and produce a clean time-series curve which is then weather normalized to produce typical load year ("TLY") shapes with sensitivities.[14] The Company then applies a Spatial Allocation process, which utilizes a tool within LoadSEER to

[9] Hr. Ex. 105, Mino Direct, p. 12.
[10] Hr. Ex. 103, Pollock Direct, Att. ZDP-1, p. 14.
[11] Hr. Ex. 105, Mino Direct, p. 36.
[12] Hr. Ex. 103, Pollock Direct, Att. ZDP-1, p. 8.
[13] Hr. Ex. 105, Mino Direct, p. 27; see Figure DCM-9.
[14] Hr. Ex. 105, Mino Direct, p. 13.

model to technology adoption and usage at a premises level.[15] This tool is the means by which the distribution planning team allocated the various forecasts, such as the EV and beneficial electrification ("BE") forecasts. The Company then conducts map adjustments to represent customer applications to interconnect load or requests for a capacity check. When a map adjustment is added, a load shape that represents the expected hourly demand of that customer is also identified and applied in LoadSEER.

40. The Company then conducts a Grid Needs Assessment ("GNA"), a summary of projected overloads and contingency risks identified throughout the 2025-2034 forecast for distribution feeders and substation banks.[16] The GNA indicates 901 combined distribution risks over the 10-year forecast period, up from 270 in the previous DSP filing.[17] The Company states that this significant increase is due primarily to 1) transportation electrification and BE and 2) the Company's adoption of a planning load limit ("PLL") standard that caps feeder utilization to 75 percent of continuous rating.[18] The Company explains that this standard has been in place for at least 20 years, but is more consistently applied in its current application as the goal of this distribution plan is to more proactively plan investments to align with evolving customer needs and state electrification and emission reduction goals.[19] The Company explains that by limiting feeder utilization to 75 percent, it will: 1) retain feeder capacity to serve loads during grid events when feeder ties close; and 2) allow the Company to stay ahead of rapidly growing load and ensure that mitigations (*e.g.*, capacity upgrades or NWAs) can be in place before load grows to 100 percent of feeder rating. The Company filed information that, as of March 2025, over half of

[15] Hr. Ex. 105, Mino Direct, p. 15.
[16] Hr. Ex. 105, Mino Direct, p. 25.
[17] Hr. Ex. 105, Mino Direct, pp. 32-33.
[18] Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, p. 66.
[19] Hr. Ex. 113, Mino Supp. Direct, p. 6.

its feeders exceeded 75 percent loading and 21 percent of feeders exceeded 100 percent of feeder capability.[20]

41. Public Service also explains that distribution planners consider a host of capacity projects to mitigate distribution risks, ranging from low-cost operational solutions such as load transfers to capital projects such as new feeders and substations to non-traditional solutions such as non-wires alternatives, targeted demand areas and virtual power plants (collectively "Non-traditional Solutions").[21] Mr. Pollock explained that Non-traditional Solutions can be thought of as being on a spectrum that considers both value provided to the system and the scalability of the solution type.[22]

b. Forecast Types

42. Public Service explains that it provided in this DSP: a forecast based on approved capacity checks (*i.e.*, customer requests for new or expanded service over 500 kW[23]); a base forecast, which includes all presumed future conditions (including customer capacity checks and five other drivers of growth in distribution services: EVs, BE, residential, commercial and behind-the-meter solar); and at the Commission's direction, the Supplemental Analysis.[24,25] The Supplemental Analysis applied new load curves for BE and EV adoption to the base forecast. Public Service also incorporated into the Supplemental Analysis additional approved capacity checks received since the development of the Company's base forecast model.[26]

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[20] Hr. Ex. 112, McDermott Supp. Direct, p. 29.
[21] Hr. Ex. 103, Pollock Direct, p. 13.
[22] Hr. Ex. 122, Pollock Rebuttal, p. 15.
[23] Hr. Tr. September 2, 2025, p. 48:2-8.
[24] Hr. Ex. 105, Mino Direct, pp. 20-26. *See* Figure DCM-D-8.
[25] Ordered by Decision No. C25-0154-I, as modified by Decision No. C25-0202-I and Decision No. C25-0260-I issued within this Proceeding. Supplemental Analysis filed as Hearing Exhibit 114 and associated attachments.
[26] Hr. Ex. 124, Mino Rebuttal, p. 22.

43. Separately, Public Service referred to the capacity check forecast derived only from capacity check data as "internal"[27] and stated at hearing that it was uncertain if that forecast was specifically entered into the record of this Proceeding.[28]

44. The Company's base forecast was the only forecast for which a detailed grid needs assessment was submitted. For that base forecast, Public Service developed overall and planning division-specific projections of non-coincident peak load being added to the system over the 2025-2034 time period.[29] These projections indicate thousands of MW in new loads due to the five growth factors, referenced above. The aggregate forecast combining all planning divisions indicates roughly 4,500 MW of new non-coincident loads by 2028, the last year of approval the Company seeks through the instant application.[30] Of that value, roughly 750 MW, or 17 percent, appears associated solely with capacity checks. Overall, the Company forecasts that its distribution system will shift from a summer-peaking system to a winter-peaking system by 2032.[31]

45. The Commission requested a Supplemental Analysis through Decision No. C25-0154-I. Specifically, the Commission required the Company to rerun the LoadSEER capacity expansion model with revised assumptions relating to residential electric EV charging and beneficial electrification-related demands and with a relaxed planning constraint whereby system upgrades would be prompted if utilization of distribution assets reached 85 percent or 95 percent (instead of a 75 percent threshold employed by the Company).[32] The Company responded that it is unable to fully satisfy the Commission's Supplemental Modeling requests for several reasons,

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[27] Hr. Ex. 105, Mino Direct, Att. DCM-9, p. 8.
[28] Hr. Tr. September 2, 2025, pp. 44:18-45:4.
[29] Hr. Ex. 105, Mino Direct, p. 26; Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, pp. 68-80.
[30] Hr. Ex. 105, Mino Direct, p. 26. Estimate based on approximation of graphic information in Figure DCM-D-8.
[31] Hr. Ex. 105, Mino Direct, p. 27. Values are estimates based on graphical information.
[32] *See* Decision C25-0154-I, ¶ ¶ 65(c)(ii)-(iv) and 65(d)(ii)-(v).

primarily due to the functionality of LoadSEER, and the fact that LoadSEER is a "living" model that is regularly updated based on new information reflecting new or changing load and system conditions.[33] The Company also said that it would take a minimum of five incremental months to manually complete the required forecasting updates, rerun the risk analysis, reevaluate all of the distribution capacity projects within the five-year distribution plan and develop new projects based on such modeling, making it infeasible under any scenario to complete the exercise within the timelines of this case.[34]

46. Public Service claims the non-coincident loads represented in the planning division-specific and aggregate base forecasts are largely irrelevant and that capacity expansion investment is required on capacity check forecast alone irrespective of suggested remaining growth factors.[35] The Company concludes that "[w]hile it is important that the Company develop and deploy an expanded set of load flexibility initiatives that can help flatten resource specific load curves and mitigate the need for new distribution infrastructure in the future, the results of the Supplemental Analysis suggests that these initiatives will have limited impact in the 2025 – 2029 period that this DSP covers."[36] However, at hearing, Public Service could not point to any specific evaluation of capacity checks alone on the record to confirm that claim, but noted that 20 percent of the system is already over 100 percent capacity utilization.[37] Public Service claims there is no overlap between capacity checks and the other growth elements (residential, commercial, EV, BE).[38]

[33] Motion for Partial Variance from Commission Decision No. C25-01540-I, p. 7.
[34] *Id*. at 8.
[35] Hr. Ex. 114C, Mino Second Supp. Direct, p. 8.
[36] *Id*. at 9.
[37] Hr. Tr. September 2, 2025, pp. 44:22-45:18.
[38] Hr. Tr. September 2, 2025, p. 49:6-18.

(1) Answer Testimony

47. Staff argues that the parties' lacked opportunity to explore alternative analyses, and that any lack of opposition to specific capacity investment is due to that lack of transparency.[39] Staff notes the LoadSEER tool is not amenable to running different scenarios with different assumptions and that the parties did not have access to or the ability to use LoadSEER to generate alternative forecasts based on alternative assumptions.[40]

48. CEO notes, as the Company admits, that the Company's capacity check forecast is not useful for planning the system over a period beyond three years. [41] Gegner recommends that the Commission should require the Company to provide, as part of its next DSP, an expanded version of the capacity check forecast that includes a lower level of projected load growth due to electrification, EV charging, and adoption of distributed energy resources other than the State-policy aligned Base Forecast if those load impacts are "lower than expected and not in line with State policy objectives."[42] WRA agrees with CEO's suggestion.[43]

49. ACE's Joan White suggests there is no real commitment behind the capacity check process. She points to the Commission's findings in the interconnection miscellaneous proceeding, "[e]xisting conceptual capacity checks—as currently conducted—are unequally applied, opaque, and provide questionable value to both customers and the Company."[44] Further, requesting a capacity check does not reserve actual capacity on the distribution system. Participants in the Commission's interconnection miscellaneous proceeding reported frustrating experiences where

[39] Staff SOP at p. 20.
[40] Staff SOP at pp. 20-21.
[41] Hr. Ex. 401, Gegner Answer, p. 24 citing Hr. Ex. 105, Mino Direct, p. 21.
[42] Hr. Ex. 401, Gegner Answer, p. 27.
[43] Hr. Ex. 1703, Kapiloff Cross-Answer, p. 4.
[44] Hr. Ex. 900, White Answer, p. 28 citing Proceeding No. 23M-0464EG, Decision R24-0242-I, ¶ 20.

they received conceptual capacity checks that purported there was available capacity, subsequently spent significant time and money developing project permitting and construction documents, only to find out when they were about to start construction that the capacity was not actually available, or that obtaining service would now require significant time or expense."[45] That order determined, among other things, that a formal service application—not the conceptual capacity check process—is what constitutes an actionable request for service or capacity with the utility.

(2) Findings and Conclusions

50. The Commission has several concerns. First, we note that the Company repeatedly assured the parties and the Commission that the proposed capacity investment is based on capacity checks alone, but then placed no analysis or results within this record for meaningful investigation by the Commission and parties. We also agree with points raised by ACE, including that capacity checks alone do not reserve distribution system capacity. Therefore, capacity checks, even if better supported, provide only modest clarity regarding future system capacity requirements. Nonetheless, we find that the Company's application provides reasonably sufficient support for the proposed capacity-related activities *presented in this DSP* for the timeframe of 2026 through 2028 given the following conclusions supported by this record: 1) the array of distribution assets currently operating above specified capacity or loading levels; 2) the statutory State goals of broad electrification of home and transportation end uses; and 3) the fact that this Application represents both the first fully litigated DSP (no settlement) and the Company's initial DSP following the relevant landmark legislation, SB 24-218. However, we find that the Company's analytic efforts in the instant case are not an appropriate long-term approach. We expect in the Company's next DSP a more fulsome analysis and underlying support of all forecasts referenced by the DSP so that

[45] Decision No. R24-0242-I at ¶ 20.

the Company's claims regarding needed investment are fully supported. Accordingly, we direct the Company to submit all relevant inputs and outputs to its base, capacity check, and any other forecasts referenced in its next DSP so that all forecasts can be quantifiably verified and evaluated in a thorough and meaningful manner.

51. With respect to the potential overlap between the various growth elements, including capacity checks, residential, commercial, BE and EV growth (as represented in the non-coincident load forecast), we find that the record was opaque and high-level, as suggested by Staff, thus offering the parties and Commission minimal detail of how it was developed or ability to update key assumptions and inputs or otherwise confirm the results or general assertion. We also agree with CEO, who raised important issues with respect to technology adoption and usage patterns. We address this more fully in the following section to this Decision.

52. Accordingly, we find it necessary to require Public Service to provide, as part of its next DSP, a more thorough evaluation of each of the growth factors represented, including both five years historical and ten years forecast values, and a comparison of historical values relative to the forecast made in the instant Proceeding. With respect to capacity checks, we require the Company to present the historical number and MW requested, and the number and MW values of capacity check requests actually served. Further, as referenced elsewhere in this Decision, we expect meaningful improvement in the collection and evaluation of Advanced Metering Infrastructure ("AMI") data as part of the Company's next DSP so that the analysis required here – as well as other Company projections of load growth – can be reasonably corroborated.

c. **Prioritization of Investments**

(1) **Positions of the Parties**

53. Staff notes that the Company has been directed by both legislation and Commission rules to prioritize DI Communities within its DSP.[46] Staff claims the Company did not specifically prioritize as required by the DSP statute.[47] Staff notes that the Company responded to a discovery request that while it does have access to reliability data and information for DI Communities, it has "not yet been able to effectuate necessary changes to how the Company prioritizes asset health and reliability projects given the timing of the DSP and related commitments in the Quality of Service Plan."[48] Staff says that while it agrees that projects adjacent to DI Communities may in fact increase reliability within these target communities, it takes issue with this *post hoc* analysis, instead of a deliberate prioritization.

54. Staff argues the Commission should take this into consideration when it evaluates whether the Company "strategically" advances the goals SB 24-218.[49] Staff also recommends that the Company should explain in its next DSP "the proactive approach the Company took in placing more weight on projects benefiting DI Communities." Staff also suggests the Company should provide a table or other comprehensive figure clearly showing the criteria used to select projects, including benefits to DI Communities, capacity constraints, and reliability issues.

55. CEO suggested the Commission adopt a specific six-step prioritization rubric focused on serving IQ/DI communities first while mitigating reliability issues, particularly those identified in the Company's Quality Service Plan ("QSP") for DI communities, and then moving

[46] Hr. Ex. 505, Turner Answer, p. 23.
[47] *Id*. at 25.
[48] Hr. Ex. 505, Turner Answer, p. 26 citing Att. JDT-3.
[49] Hr. Ex. 505, Turner Answer, p. 30.

onto infrastructure that serves non-IQ/DI customers, initially assets with emergent reliability issues and then, finally, those without reliability issues but necessary to serve projected energization requirements.[50] CEO contends that its proposed framework builds from the prioritization of investments contemplated in section 40-2-132.5(c)(III) and (IV), C.R.S.

56. WRA similarly argues that the Commission should ensure that distribution system investments adequately support reliability and policy goals related to electrification and distributed energy resource adoption in disproportionately impacted communities.[51]

57. Staff supports the Company's practice of designing to 75 percent utilization of feeders, stating that doing so is good engineering practice and that a reactive approach is not sustainable given the speed of load growth due to electrification. However, it takes issue with the notion that a feeder forecasted to surpass the 75 percent threshold should trigger plans to upgrade that line, suggesting that doing so without proper safeguards runs the risk of overbuilding the system, which increases costs for ratepayers and the potential for stranded assets. Staff argues that the Company's approach does not sufficiently balance this risk to customers because it does not adequately account for forecasting uncertainty.[52]

58. Staff argues that the Company's Direct and Supplemental testimony provides no discussion regarding how the Company accounts for the inherent uncertainty in any probabilistic forecast, how that uncertainty grows the farther into the future the forecast attempts to model, and that as a result, the Commission has little visibility into how the Company prioritizes risks and projects, and how these processes change in between proceedings. Whereas the Company argues that load uncertainty creates potential for underbuilding and justifies aggressive investment in

[50] Hr. Ex. 400, Durkay Answer, pp. 6-7.
[51] Hr. Ex. 1700, Valentine Answer, p. 25.
[52] Hr. Ex. 502, Bongiardina Answer, pp. 14-15.

capacity addition, Staff states that this ignores the risk of overbuilding, the costs of which would be borne entirely by ratepayers.[53]

59. Staff discusses three sources of uncertainty in the Spatial Allocation process by which the Company allocates service-area-wide projections of technology adoption to individual premises— "adoption points," and subsequently to specific distribution assets. These are 1) the adoption points, 2) the technology load curves, and 3) the Company-level load growth forecasts for each end-use technology. As a result of these uncertainties, Staff urges the Commission to be skeptical of approving the Company's forecast-based approach to capacity investments without explicit guardrails that protect ratepayers from excessive costs.[54]

60. To account for these sources of uncertainty in the Company's forecasts of distribution asset loading, Staff recommends that the Commission order the Company to adopt a Risk Uncertainty Framework ("RUF"). Staff proposes that this RUF would address uncertainty by systematically raising the loading threshold that triggers a remediation project depending on how far into the future loading is expected to exceed the technical planning limit for the asset (*i.e.*, 75 percent of continuous capacity for feeders and 100 percent for banks and substations). Based on Company testimony that feeders, banks and substations require two, three, and five years respectively to complete, Staff proposes that the load threshold at which a project would be triggered be raised by three percentage points for each year beyond these time-to-complete durations by which the model forecasts excessive load for a given asset. For example, if the load on a feeder is projected to exceed 75 percent three years in the future (*i.e.*, one year longer than it takes to upgrade the feeder), then a mitigation project would not actually be triggered unless the

[53] *Id*. at 16-17.
[54] *Id*. at 19-24.

load in year three was projected to exceed 78 percent. Staff states that it is open to adjusting the RUF with input from other parties to ensure that it reasonably balances the protection of ratepayers with the actual project timelines, and assessment of risk for different assets.[55]

61. Staff contends that the RUF would "de-weight" future risks by raising the threshold that triggers a project, rather than treating a risk eight years in the future identically to one only two years in the future. This could result in a re-prioritization of projects, though it would still yield enough flexibility that the Company could move forward with a project if it found that a near-term risk is severe enough. Staff states that with the RUF in place, the Company would have to explicitly consider the uncertainty of future risk, and in doing so, share more of the financial risk with customers of going forward with that project. Staff contends that the RUF provides the Commission with a tangible framework to help assess whether decisions were prudent with respect to both the Company's forecasted capacity needs and the inherent uncertainty in the underlying forecasts, and that if the Company chooses to pursue projects that fall outside of the RUF, then the Company should be able to explain why the project was still necessary and why other strategies could not address the forecasted risk. Staff makes clear that it is not proposing any change to the 75 percent technical planning limit nor to the NWA consideration threshold of 75 percent.[56]

62. Citing a discovery response, the UCA claims the Company failed to evaluate the impact of a higher technical planning limit on the GNA, characterizing this as a missed opportunity to reduce capital investment needs. UCA argues that the absence of feeder- or system-level metrics such as the System Average Interruption Duration Index ("SAIDI") or the System Average Interruption Frequency Index ("SAIFI") prevents a factual evaluation of whether the 75 percent

[55] *Id*. at 24-28.
[56] *Id*. at 28-36.

PLL improves customer reliability. Furthermore, UCA contends that the Company has provided no evidence that load additions at feeders between 75–100 percent of their continuous rating have led to customer delay or reliability failures.[57]

63. While acknowledging the operational flexibility provided by the 75 percent planning limit, UCA expresses concern that the Company did not fully explore NWAs and load flexibility options that could also increase resiliency. UCA recommends that the Commission reduce the Company's proposed distribution budget, arguing that the 75 percent technical planning limit is being applied without adequate justification of its cost-effectiveness. UCA suggests that while the 75 percent threshold may serve a purpose in N-1 contingency planning, it should not be uniformly applied as a capital investment trigger. UCA also suggests prioritizing mitigation of high-impact, short-term risks over long-term capital projects that rely on uncertain forecasts and may overstate the need for distribution investments.[58]

64. SWEEP/NRDC recommend that the Company be directed to improve its planning for capacity upgrades in the next DSP application by adopting a more granular, time-based approach, moving beyond the current 75 percent PLL method. They contend that the current approach, which triggers mitigation projects when a feeder's demand exceeds 75 percent of its continuous rating, does not adequately account for the wide variation in time it takes for different feeders to move from 75 percent to 100 percent of capacity, which can be as short as one or two years or as long as six or more years. Since a feeder upgrade project takes approximately two years to complete, the 75 percent PLL approach risks both implementing upgrades too early for some feeders and running a significant risk of overloads for others.[59]

[57] Hr. Ex. 602, Konidena Answer, pp. 28-37.
[58] *Id*. at 41-57.
[59] SWEEP/NRDC SOP at pp. 22-24.

65. To address these issues, SWEEP/NRDC recommend adopting a more accurate time-based planning approach for capacity upgrades in the next DSP. The two options they propose for this approach are the "Time-based (Exact)" option and the "Time-based (Buffer)" option. Both options calculate the year a feeder or substation bank is projected to reach 100 percent capacity and then designate the N-0 overload trigger year by moving that date back based on the necessary project lead time (*e.g.*, two years for feeders, three years for banks/transformers, and five years for substations). The "Time-based (Buffer)" option adds an extra one-year buffer to the project lead time. SWEEP/NRDC's analysis suggests that implementing either time-based approach in the next DSP would result in fewer feeder upgrades but more bank upgrades compared to the current 75 percent PLL method.[60]

66. SWEEP/NRDC continue to advocate for the time-based planning method despite Public Service 's clarification that the 75 percent PLL is merely a screening tool, not an automatic trigger for funding a project. On rebuttal, the Company explains that it "further prioritize[s] the most critical projects" after the initial screen. However, SWEEP and NRDC argue that the Company's current process lacks transparency, as there is no documentation showing how Public Service analyzes the 75 percent PLL feeders to determine which ones to upgrade, or why 53 feeders that exceed the N-0 limit are not funded in the current five-year budget. The time-based approach would create greater transparency regarding the distribution system's real overload risks and the predicted timing of those risks.[61]

67. Denver argues for a more nuanced approach to determining when capacity projects are needed than the Company’s proposed PLL thresholds. It states that exceedance of the loading

[60] SWEEP/NRDC SOP at pp. 25-26.
[61] *Id*. 26-28.

threshold should trigger a process by which the Company further scrutinizes the urgency of the mitigation solution and lower-cost opportunities to avoid or delay capital investment. Denver indicates that this would help the Company to prioritize projects that appear to be on a near-term, high-growth trajectory, while others may simply be flagged for a higher level of monitoring and proactive mitigation solutioning, so that the Company would be ready and able to implement solutions according to each situation.[62]

(2) Rebuttal

68. Company witness David Mino suggests that much of the intervenor response to the 75 percent planning load limit reveals the misconception that a capacity project is triggered whenever a line is forecast to exceed that threshold. Mino clarifies that the threshold qualifies a line for a project, but that the Company does not fund all such N-0 risks, rather it considers growth rate and allows feeders to be loaded up to 100 percent. He points out that the GNA has 53 feeders above 75 percent loading that do not have a mitigation project funded in the budget presented in this Proceeding. He states that mitigations are prioritized where they can solve multiple risks. Mino characterizes UCA's recommendation for ten percent reduction in the capital budget as arbitrary. He argues that the PLL does not inflate the capacity budget at all, and that it is warranted because it will provide flexibility to address the potential for rapid load growth in specific locations and aligns asset ratings across the distribution system and substation equipment.[63] He further asserts that there is no analytical basis behind UCA's ten percent budget reduction, contending that it is based solely on a general concern that the Company is proposing too much infrastructure investment relative to non-infrastructure solutions. Mino contends that UCA does not account for

[62] Denver SOP at pp. 7-10.
[63] Hr. Ex. 124C, Mino Rebuttal, p. 29.

the fact that the capacity budget is driven by current capacity constraints and near-term, known load additions.[64]

69. Mino argues against the SWEEP/NRDC recommendation to use a time-based rather than load-based trigger for capacity projects, noting that the Company's planners consider the speed of load growth when deciding which projects to fund, and that the Company designs mitigations to address multiple risks. He states that even if growth is slower than anticipated on a given feeder, a mitigation project driven by other risk considerations may still make it appropriate, and contends that the Company's approach is flexible, placing greater weight on current and near-term changes that are less uncertain.[65]

70. With regard to the Staff RUF proposal, Mino states agreement that forecasts are more uncertain in the latter years of the forecast, but argues that the Staff proposal has no engineering, evidentiary, or analytical basis. He asserts that the Company's iterative process is a better approach, in that it observes trends as they develop and adjusts its plans and budgets accordingly, noting that the Company is seeking approval for short-term investments in this DSP.[66]

71. In its SOP, Public Service asserts that its proactive planning process results in affordable solutions to meet the identified need by efficiently deploying capital and iterating on an annual basis to ensure capital is only deployed if and when needed. The Company states that its process selects least-cost solutions, designs projects to address multiple risks (averaging 4.5 risks per project), and makes careful decisions about whether to fund projects based on the magnitude of issues they address, avoiding piecemeal solutions which may reduce short-term cost at the

[64] *Id*. at 35.
[65] *Id*. at 29-32.
[66] *Id.* at 32-33.

expense of long-term affordability, noting that delaying investment in the current inflationary environment could ultimately impose higher costs on customers.[67]

72. Regarding the DI prioritization proposals put forth by parties, Public Service responds 1) the filing of the Company's DSP occurred only a short time after the passage of SB 24-218. That timing did not leave a substantial amount of time for the Company to conduct a full re-evaluation of projects based on the statutory factors beyond how the Company prioritizes projects through LoadSEER and its existing procedures; 2) the suggestions of CEO and Staff to craft different and broader priority "frameworks" will only add complexity and reduce the flexibility the Company has to address emergent needs across its system; and 3) IQ/DI Prioritization is not relevant to issues of cost recovery via the GMAC.[68] However, the Company notes, it conducted an analysis to determine the extent to which their capacity project planning process had resulted in planned projects that will be located in and benefit disproportionately impacted communities.[69] Public Service contends that "[a]fter evaluating the projects, the Company determined that 117 of the 154 projects (about 76 percent) in that 4-year period 2 directly benefit at least one DI community throughout Colorado. Of those 117 projects, 103 projects provide benefits to communities with more than one DI community type."[70] Public service explains that planned projects could benefit DI communities in one of two ways: 1) where the buildout is directly in a DI community; and, 2) where the buildout is not directly in a DI community but directly supports distribution capacity expansion or reliability in a nearby DI community. The Company also notes that SB 24-218 references to prioritization references "must be read in

[67] Public Service SOP at pp. 8-10.
[68] Hr. Ex. 121, Ihle Rebuttal, pp. 81-82.
[69] Hr. Ex. 105, Mino Direct, p. 40.
[70] *Id.*

light of the context of the entire statute, which attempts to address a range of legislative goals. Upgrades to the distribution system in DI Communities are an important part of the Plan, but they are not the only goal of a Distribution System Plan. Nor does the statute indicate that work in DI Communities is to be done at the expense of meeting the other policy objectives. Instead, the Commission must consider the entire statute and balance the need to make investments that advance multiple objectives, just as the Company's DSP does."[71] The Company reiterates that 76 percent of the capacity budget would benefit DI communities. The Company also argues that CEO's proposed framework is not based on any engineering analysis and is simply not necessary to ensure investment in DI Communities.[72]

(3) Findings and Conclusions

73. Both Staff and SWEEP/NRDC offer capacity project prioritization methodologies intended to focus investments on the most time-sensitive projects, leaving less critical projects for future years. We note Company testimony that while it uses a forecast exceedance of the PLL as a <u>threshold</u> consideration, that is not the only determinant of a decision to initiate a capacity upgrade, as it considers asset age, a project's ability to mitigate multiple contingencies, the speed of load growth and other factors when determining whether to fund a project. While there is record evidence that the Company chose not to fund certain projects in the grid needs assessment where the PLL was exceeded, there is nothing in the record that indicates whether or by how much the Staff or SWEEP/NRDC proposals would reduce capital spending in each year of the plan. Given the Company's statements regarding its prioritization process, we acknowledge that neither of these proposals is guaranteed to have significant impact on capacity project selection.

[71] Hr. Ex. 121, Ihle Rebuttal, p. 84.
[72] Hr. Ex. 121, Ihle Rebuttal, p. 88.

Nonetheless, we find that SWEEP/NRDC proposal, which would tie project selection to the demonstration that absent the proposed project one or more distribution assets would exceed their rated capacities within a year of project completion, will provide an informative counterpoint to the Company methodology in the next DSP. Accordingly, we direct the Company to include a comparison of its proposed capacity budget for each load scenario with a capacity budget developed using the "exact" SWEEP/NRDC methodology (*i.e.*, without the one-year buffer) in direct testimony of its next DSP application.

74. The Company's approach to prioritization of DI Communities, as SB 24-218 requires, and its relationship to other policy objectives of the statute is not identified in a straightforward way. We are concerned that the prioritization framework suggested by CEO could reduce the Company's ability to solve emergent reliability issues. The Commission notes there is not necessarily a clear distinction between whether a distribution feeder or other asset serves an IQ/DI community, a non-DI/IQ community or both. However, in instances where there is a distinction, the Company is required by the DSP statute to prioritize investments that improve infrastructure for income-qualified or disproportionately impacted communities with residential capacity constraints.

75. We do agree with Staff that Public Service should explain in its next DSP the proactive approach the Company took in placing additional weight on projects benefiting DI/IQ Communities in order to correct prior differences in service reliability. We also require the Company to facilitate the record in its next DSP by providing historic and projected reliability data for DI/IQ and non-DI/IQ communities separately, by census block, so that the Commission can ensure DI/IQ communities have not, and will not, be served less reliably than their non-DI/IQ counterparts and that any reliability improvements are enjoyed by IQ/DI communities in addition

to the system at large. Such considerations should also be made when the performance framework is considered.

d. Technology Adoption and Usage Patterns

76. At the March 13, 2025 technical conference, held jointly for the JTS Proceeding and instant proceeding, the Company explained that it designed the modeling of the bulk system and the distribution system to create "[a]lignment of key input assumptions between JTS and DSP."[73]

77. In the JTS Proceeding, Public Service projected technology adoption values of roughly half a million EVs and residential hot water heat pumps, each, by 2030 and annual growth of over 100,000 units for each technology in its service territory.[74] The Company conducted a second, slightly lower forecast of EVs referred to as the "Mid" level forecast whereby 2030 adoption levels reached roughly 566,000 (about 129,000 less than the "High" level scenario included in the Base forecast). With respect to the Company's BE adoption projection, the Company submitted information indicating that BE adoption patterns, especially for hot water heaters, were well behind expected values.[75]

78. With respect to the electric capacity requirements of BE technologies, Public Service presented a limited set of data of 114 customers to support efficiencies of HP retrofit, generally referred to as the Electric-Prem data. The Company calculates that most fall within having a peak winter load ranging from 11 kW – 19kW.[76] A party to the JTS, SWEEP and

[73] *See* https://www.youtube.com/watch?v=DARUSuUw39U&t=5484s at approximately 42:00-43:05 of the recording.
[74] *See* Proceeding No. 24A-0442E, Hr. Ex. 101, Att. JWI-2, Vol. 2, Tables 2.2-7 and 2.2-8.
[75] Hr. Ex. 109, Filing of Additional Information, Att. 4.
[76] Hr. Ex. 109, Filing of Additional Information, Exec. Att. 3, "All Electric Premise" tab.

WRA, argued that the Company evaluated the data incorrectly, and that the total peak load of homes retrofit with BE heat should be far lower.[77]

79. The Commission decision in the JTS Proceeding required Public Service to assume the lower "Mid" level EV adoption curve and update that input as actual adoption values are available over time.[78] The JTS Proceeding also modified the Company's BE adoption forecast to account for recent delays in deployment and to assume a continuation of the last year of funding, escalating at inflation, based on the Commission's most recent relevant decision. The JTS ruling also required the Company to apply modified usage patterns for heat pump water heaters, assume higher EV managed charging participation rates, and to assume a maximum 10 kW per household coincident peak load associated with BE retrofit.[79]

(1) Answer Testimony

80. UCA suggests the DSP lacks proper coordination with other Company plans including the Wildfire Mitigation Plan ("WMP"),[80] JTS Proceeding, Mountain Energy Proceeding ("MEP"),[81] and transmission planning, and that the capital spending proposed in the instant proceeding is based on assumptions already determined inappropriate in the JTS.[82] UCA states, "[a]larmingly, the Company does not plan to update its DSP forecasts for this Proceeding based on the outcome of the JTS Proceeding. The Company has only suggested that updated forecasts would likely go into the analysis of the next DSP when it is filed in 2027."[83] UCA also suggests the distribution investment required under the MEP should be reported here in this DSP.

[77] *See* Decision C25-0747 in Proceeding No. 24A-0442E, ¶¶ 148 and 151.
[78] Decision C25-0747, ¶ 141.
[79] Decision C25-0747, ¶ 157.
[80] Proceeding No. 24A-0296E.
[81] Proceeding No. 25A-0044EG.
[82] UCA SOP at pp. 3-6.
[83] UCA SOP at p. 5.

Public Service's approach creates a "myopic separation between distribution needs identified in the gas planning context and distribution needs identified in the DSP."[84]

81. AEU argues that Public Service's BE load calculation was invalid because it assessed the peak load of each home adopting an air source heat pump regardless of coincidence with each other. AEU calculated using same Electric-Prem data that the *average coincident* whole-home meter does not exceed 7 kW in total.[85] Instead, the Company's methodology for assessing heat pump impacts was to *add* 7.15 kW of assumed incremental heating load to each individual site, on top of other existing house loads like lighting, water heating, appliances, or plug loads.

82. CEO noted the Company is well behind in BE implementation, especially hot water heat pumps. As of first quarter 2025, Public Service had distributed a total of 35 heat pump water heater rebates (compared to 45,000 projected for the year) and 154 air source heat pump rebates (27,000 projected for the year).[86]

83. WRA argues the Company's LoadSEER forecasting tool inappropriately generalizes transportation electrification load shapes and adoption curves.[87] First, the Company's model fails to differentiate between battery EVs and plug in hybrid EVs, even though the two have significantly different ranges and charging load shapes. Next, the Company's model "unnecessarily muddles" Level 2 and DCFC charging levels, which overstates demand from Level 2 charging and understates capacity requirements to serve DCFC loads.[88] Finally, according to WRA, the Company has made faulty assumptions regarding where public charging will be

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[84] UCA SOP at p. 6.
[85] Hr. Ex. 2101C, Burgess Answer, p. 58.
[86] Hr. Ex. 401, Gegner Answer, p. 21 citing Xcel Energy, Q1 2025 DSM Roundtable Presentation (May 14, 2025), at 7.
[87] WRA SOP at p. 18.
[88] *Id*. at 18-19.

located along the distribution system, whereby the Company assumes public charging at every available parking lot.[89] WRA argues Public Service should use appropriate geospatial targeting to model feeder and substation-specific EV public charging levels, in conjunction with predicative modeling tools for an alternative forecasting view.

84. With respect to BE, WRA argues the Company's load forecasting should use updated electrification technology load profiles, informed by advanced metering infrastructure data and program experience, and account for anticipated load growth from non-pipeline alternatives associated with the gas system.[90] The Company's load forecasting should strive to align key inputs for electrification technologies and distributed energy resources with those used in other proceedings, such as Gas Infrastructure Plans and Electric Resource Plans. Finally, WRA suggests the Commission should consider revising cost-benefit analysis processes in a manner that acknowledges the statutory directive for utilities to plan for BE, though WRA admits this action is outside the scope of this Proceeding.[91]

(2) Rebuttal

85. The Company responds that its distribution planning efforts apply consistent load growth forecasts, DER adoption forecasts, technology curves, and other underlying assumptions with its resource and transmission planning efforts, although there are some minor differences due to "vintage and other considerations."[92] The Company also contends its distribution plan is required to provides the capacity necessary to meet various goals established by the Legislature in SB 24-218, including its Clean Heat Plan, Transportation Electrification Plan, and Demand-Side

[89] WRA SOP at p. 19, citing Hr. Ex. 105, Att. DCM-9, at 25; Hr. Ex. 105, Conf. Att. DCM-4C.
[90] WRA SOP at p. 20.
[91] WRA SOP at. p. 20.
[92] Hr. Ex. 124C, Mino Rebuttal, pp. 13-14.

Management/Beneficial Electrification plans. "By incorporating long-term Company-wide technology adoption based on those plans (or the proposals available when modeling was conducted for plans that were not approved when the DSP was prepared), Public Service is satisfying that requirement."[93]

86. The Company also noted that it plans to improve its use of LoadSEER including refinement of the technology adoption load curves using AMI data and "allowing for different load shapes to be used for the allocation of the same technology type."[94] Public Service suggests it provided in this DSP its base forecast, the capacity check forecast, and at the Commission's direction, the Supplemental Analysis, which used different load curves for BE and EV adoption and additional approved capacity checks to Public Service's Base model.[95] Separately, Public Service referred to the capacity check forecast as internal and wasn't certain if it's on the record.[96]

(3) Findings and Conclusions

87. As previously mentioned, the Commission ruled on many of the suggestions previously through the JTS Proceeding. We find it necessary to affirm our guidance as it relates to common adoption, efficiency and usage pattern inputs to the Company's models for use in resource planning and distribution planning. Specifically, the Company should incorporate in its LoadSEER forecasting the adjustments to technology adoption and usage patterns required in the Commission's JTS decision for purposes of the revised forecast in the Company's next DSP. The list of requirements made in that proceeding include:

[93] *Id*. at 14.
[94] *Id.* at 22.
[95] *Id*.
[96] Hr. Tr. September 2, 2025, p. 44:22-45:4.

- Differentiate between BEV and PHEV;
- Start with EVs already on the system;
- Assume 50 percent managed charging for BEV, 90 percent for PHEVs by end of decade;
- Evaluate Level 2 and DCFC charging uniquely as proposed by WRA and apply specific patterns if appropriate;
- Refine public charging peak load and geospatial assumptions based on actual installation trends, AMI usage data and other relevant inputs;
- Reset BE adoption trends based on actual through Q3 2025;
- Set household with air source heat pumps peak use at 10 kW as determined appropriate in JTS; and
- Alter hot water heat pump load profile to flatten load shape.

88. We note that AEU produced analysis indicating average coincident home usage for BE retrofit customers is below 7 kW. However, we find the 10 kW value deemed appropriate in the JTS Proceeding provides a reasonable cushion while the Company conducts a more thorough evaluation leveraging AMI data. The Company should apply the 10 kW value in its LoadSEER projection model for the time being. For its next DSP, the Company should produce a thorough evaluation of usage patterns including load shapes and magnitudes for a range of adoption cases of electrification technologies including new and retrofit homes through the analysis of AMI data base. If the Company does not have the personnel or expertise to evaluate the AMI data, it should hire an outside consultant to conduct the AMI evaluation and make that consultant available for cross-examination in the next DSP adjudication.

2. Capacity Budget

a. Direct Case

89. The Company's DSP application originally contemplated the necessary investment for the 2025-2029 period. For that five-year time-frame Public Service proposed implementation

of 35 new substations, 108 upgraded or new substation banks (also referred to as substation transformers), and more than 300 distribution feeders totaling $2.079 billion.[97] Upon Rebuttal, the Company narrowed the budgetary request to the years 2026-2028, proposing $413 million in 2026, $478 million in 2027 and $472 million in 2028 (for a total of $1.363 billion) based on its GNA. As referenced above, the GNA is a summary of overloads (referred to as "N-0") and contingency risks (referred to as "N-1") identified throughout the 2025-2034 forecast for distribution feeders and substation banks. To mitigate the assessed grid needs, the Company developed 180 proposed capacity projects, 145 of which are considered "Major Distribution Grid Projects."

[97] Hr. Ex. 105C, Mino Direct, p. 44.

90. Direct case and Rebuttal case proposed investments for all DSP categories and non-DSP distribution investment (approved through the TEP and WMP cases, respectively) are shown in the table below:

DSP Budget ($M)	2023	2024	2025	2026	2027	2028	2029	Total - Direct Case 2025-2029 Budget	Total - Rebut. Case 2026-2028 Budget
Capacity	100	122	289	413	478	472	427	2,079	1,363
Non-Capacity									
Asset Health & Rel.	209	225	286	320	342	364	400	1,712	1,026
Tools & Comms	16	20	13	13	16	17	17	76	46
Mandates	49	51	53	54	55	56	57	275	165
New Business	135	190	132	137	145	159	162	735	441
Sub-total: Non-Cap.	409	486	484	524	558	596	636	2,798	1,678
Proposed DSP	**100**	**122**	**289**	**413**	**478**	**472**	**427**	**2,079**	**1,363**
								-	-
Non-DSP Distribution Inv.									
TEP	19	21	53	86	90	106	107	442	282
Wildfire	120	230	324	412	505	455	468	2,164	1,372
AGIS	80	77	27	2	10	-	-	39	12
Sub-total: Non-DSP Dist.	219	328	404	500	605	561	575	2,645	1,666
Grand Total: Distr. Inv.	**319**	**450**	**693**	**913**	**1,083**	**1,033**	**1,002**	**4,724**	**3,029**

The Company utilized a model called LoadSEER to develop its GNA. LoadSEER develops load models for each feeder, bank and substation on the distribution system based on Capacity Checks (customer requests for new service or service expansion) and projections of load growth from existing customers (*e.g.*, from BE and TE).

b. Positions of the Parties

91. UCA criticizes the Company's treatment of DERs, asserting that their value is systematically underestimated due to LoadSEER limitations and a failure to model their contribution to reliability in overload and contingency events. UCA complains that the Company is taking a narrow view of how demand response and load flexibility programs can support the distribution system, favoring conventional capacity investments now while developing flexibility

programs for the future. Consequently, UCA recommends that the Commission reduce the Company's proposed capacity budget by ten percent, direct the Company to focus on short-term investments, and mandate the incorporation of large DERs, such as Community Solar Gardens and off-site solar, as viable mitigation tools for both N-0 and N-1 risks.[98]

92. SWEEP/NRDC recommend that the Commission approve the Company's proposed capacity budget, subject to targeted modifications. SWEEP/NRDC contend that the primary issue in this Proceeding is whether the Commission should approve Public Service's proposal or opt for the more limited proposals from Staff and the UCA. SWEEP/NRDC urge the Commission to approve Public Service 's proposed budget for capacity upgrades but with several targeted modifications aimed at reducing customer costs, such as improvements to the Company's 75 percent PLL approach.[99]

93. SWEEP/NRDC contend that the argument for approving Public Service's budget is rooted in SB 24-218, which requires the Company to implement a robust DSP that advances electrification and reduces barriers to energization and interconnection. They state that the General Assembly recognized the need for substantial and strategic upgrades to meet Colorado's climate and electrification goals, acknowledging that system constraints limit customers' ability to cost-effectively interconnect DERs and energize BE resources. They emphasize that the law established that it is a matter of state urgency to ensure sufficient capacity on the distribution system to affordably and reliably support decarbonization goals and consumer demand for retail distributed generation and BE. SWEEP/NRDC assert that the proposals put forth by Staff and UCA would not advance the General Assembly's legislative intent. They state that Public Service

[98] *Id*. at 71-76. 80-81, 116-125.
[99] SWEEP/NRDC SOP at pp. 4-5.

's proposal includes the necessary "timelines and budgets to create sufficient hosting capacity" and identifies the "specific distribution system investments needed to strategically support" the State's decarbonization laws and policies, a fact which no party has disputed would achieve the overall statutory objective of upgrading the distribution system. SWEEP/NRDC argue against Staff's and UCA's concerns regarding the size of the DSP and bill impacts, emphasizing that the Commission's primary job is to ensure the DSP achieves the statutory goal of robust and proactive distribution system upgrades, which must take precedence over the other issues raised.[100]

94. CEO states that it generally agrees with the Company that its proposed budget for investments in the distribution system can and will support State policy goals, but recognizes that the scale of the investment the Company has proposed in this DSP will have very real bill impacts to customers. CEO also recognizes that there is more information the Company could have provided to help the Commission and parties understand how the proposed investments achieve the outcomes contemplated in Commission rules and statute. CEO ultimately recommends the Commission approve the Company’s DSP, with modifications, and that the Commission emphasize the need for the Company to provide additional information in forthcoming advice letters and future DSPs.[101]

95. WRA argues that the Company’s distribution system is "woefully unprepared for all growth" and needs significant capacity investments to meet state energy policy goals.[102] WRA asserts that while SB 24-218 anticipated incremental investment for load growth driven by electrification, the evidence in this Proceeding shows that the need for investment is overwhelmingly due to an aging and already-constrained system. WRA stresses that the

[100] *Id*. at 5-9.
[101] CEO SOP at pp. 7-10.
[102] WRA SOP at p. 15.

Commission should understand that forecasted load growth from electrification is not the primary *cause* of the capacity investments, though these investments will be critical for creating the necessary headroom to support electrification and other state policy goals.[103]

96. WRA calls on the Commission to approve a robust portfolio of capacity investments based on the current state of the grid, which has "minimal or no capacity to accommodate new load," citing evidence that over 20 percent of the Company's feeders already experience peak loading beyond their rated capacity, and an additional 30 percent are loaded above the 75 percent technical planning limit. WRA states that this has had real-world consequences, including "delays and cancellations" for projects such as affordable housing, general development, and electrification initiatives. WRA concludes that the statutory requirement for Public Service to upgrade its system necessitates the approval of a robust portfolio of capacity investments.[104]

97. WRA recommends that the Commission explicitly acknowledge that capacity investments are driven by near-term customer capacity requests and existing system load, rather than long-term electrification forecasts. Company testimony clarified that "current loading" and near-term capacity checks are the overwhelming drivers of the budget, not future forecasting. By explicitly stating this in its decision, the Commission would provide transparency to customers and the public about the actual cause of the distribution investments that will be recovered through the GMAC.[105]

98. Boulder argues that the record establishes that the proposed scope of new capacity spending from 2026 to 2028 is essential due to existing short-term constraints and a rise in new service applications. Boulder argues that concerns about uncertain long-term forecasts are less

[103] WRA SOP at pp. 12, 15.
[104] *Id*. at 16.
[105] *Id*. at 16-17.

relevant and should be addressed in a future DSP filing. It notes that the Company testified that 21 percent of its distribution feeders are currently loaded beyond 100 percent of their capacity, and contends that it is undisputed that the utility must address these 100 percent constrained lines "right away" to avoid delays in interconnection processes and other impacts on its ability to serve customer needs.[106]

99. Boulder supports the approval of the entire capacity plan for the three-year period to prevent Public Service from remaining in a reactive state with a large portion of its system overloaded, particularly as new customer growth continues. Boulder notes that several Company witnesses testified that service applications are increasing in both number and scope, including new all-electric buildings, housing developments, and large industrial or data centers. This increase in demand means the need for capacity is driven by actual service applications from customers, with the goal of resolving short-term needs and alleviating existing system constraints. Boulder notes further that 173 of the 180 capacity projects identified in the GNA are aimed at solving short-term needs on the system. It contends that holistically addressing current and reasonably expected future needs within a single project is sound practice because it achieves cost efficiencies for ratepayers. Upgrading equipment at the end of its life, for example, is often paired with upsizing the equipment to provide additional capacity based on engineering judgment, which Boulder's witness testified is a "no-regrets investment" that facilitates future growth.[107]

100. Boulder’s witness Telischak confirmed that the specific capacity projects are appropriate, stating that the Grid Needs Assessment correctly reflects the current constraints within the Boulder Division, the high rate of EV adoption and BE in the region, and aligns with loads

[106] Boulder SOP at pp. 13-14.
[107] *Id*. at 14-15.

from new and re-development. Telischak concluded that the recommended improvements for the Boulder Division are in the best interest of the system. Boulder highlights that no party in the Proceeding opposes any of the specific capacity projects on the basis that they are not in the public interest; the only opposition centers on the most appropriate cost recovery mechanism.[108]

101. Denver states that it is broadly supportive of the near-term investments proposed in the DSP, especially those investments intended to address known capacity constraints in the intervening years before the next DSP is filed. It notes that capacity constraints on the Company's distribution system over the past several years have inhibited Denver residents and businesses from pursuing electrification strategies that directly support state and local policies and priorities, and that these constraints have contributed to severe delays and added costs for projects, including infill housing and affordable housing developments. Denver contends that "[w]e cannot afford to allow system constraints to continue to stifle progress to meet state goals."[109]

102. Denver points to record evidence indicating that the Company's distribution feeders are increasingly operating beyond their design limits, noting that in the Denver Metro Planning Division, nearly two-thirds of feeders are operating at or above 75 percent of their rating and one-third of feeders are operating beyond 100 percent of capacity, with a similar trend for transformer banks. Denver argues that at a time when the state is trying to electrify both transportation and space heating, the Company's proposed investments are imperative.[110]

103. The East Metro Area Business Coalition is also supportive of the Company's capacity budget. In addition to citing the record evidence about the heavy loading of existing distribution assets, Eastern Metro Area Business Coalition points to record evidence that

[108] *Id* at 15.
[109] Denver SOP at pp. 5-6.
[110] *Id*. at 6-7.

approximately $2.5 billion of debt has been issued within the Eastern Metro Area Business Coalition's boundaries by various metro districts in order to support infrastructure needed for current and future development. It contends that this demonstrates that the Company is not alone in anticipating dramatic growth in the need for additional electric distribution service. Eastern Metro Area Business Coalition contends that failing to adequately expand the distribution system will stunt future development and result in lost opportunities to expand Colorado's economic development, add jobs and create an expanded tax base to fund future governmental services and educational opportunities. Eastern Metro Area Business Coalition states that it has entered the regulatory arena for the sole purpose of ensuring adequate electric resources to serve the needs of the Eastern Metro Area Business Coalition membership and their customers. It contends that the danger of not building sufficient capacity is too great for the Coalition to stand on the sidelines, given the opportunities available to advance the economic viability of the Denver Metro Area and the state as a whole.[111]

104. The Company notes that most parties either support or do not challenge its budget proposals, and cites record evidence that near-term capacity needs are driven by current constraints and near-term load additions from customer applications for loads above 500 kW. It refers to the fact that as of 2024, 21 percent of its feeders experienced loads above 100 percent of rated capacity, and notes that in the year that elapsed between its direct and supplemental direct filing, an incremental 205 capacity checks (new load applications) were approved, representing an increase of 273 MW. It contrasts this with the Company's experience between 2018 and 2023, when the Company received an average of 100 capacity check applications per year. The Company contends that constraints on the distribution system already impact customers seeking to interconnect and

[111] Eastern Metro Area Business Coalition SOP at pp. 3-4.

inhibit both electrification and economic development goals. It states that approval of its capacity budget will allow it to proactively invest in the distribution system over the short term to help to ensure that the distribution system can be available for safe and reliable service to customers, in support of the goals of SB 24-218.[112]

c. Findings and Conclusions

105. While several parties, including Commission Staff and SWEEP/NRDC offer recommendations regarding alternative methods to identify and prioritize capacity needs, we note that with one exception, party testimony on the proposed Capacity budget is overall supportive of the Company proposal. The only party that challenges the Company's proposed Capacity budget is UCA, which recommends a ten percent reduction. However, we find no substantive record support behind UCA's specific budget adjustments. Nonetheless, as we express elsewhere in this Decision, we have numerous and significant concerns related to the Company's modeling and forecasting processes as well as the longer-term rate impacts associated with the Company's overall level of capital spending. We also find elsewhere in this Decision that the record does not clarify the optimal application of non-traditional distribution solutions (*i.e.*, NWA, TDA, VPP, flexible interconnection). While these concerns remain and will be the subject of intensified scrutiny in future DSP Proceedings, we find that the Company has demonstrated that existing system conditions and near-term load growth appear to be driving the need for the majority of the capacity investment it proposes in its budget

3. Non-Traditional Solutions and NWA/TDA Settlement

106. Pursuant to the Commission's DSP Rules, a utility shall present alternatives to traditional investment, including potential pilot programs and utilization of existing programs and

[112] *Id*. at 11-14.

resources to address grid needs. Major distribution grid projects identified to be necessary in the grid needs assessment conducted pursuant to Rule 4 CCR 723-3-3532 shall be subject to an NWA suitability screening to determine if an NWA may be a suitable alternative to traditional utility infrastructure solutions.[113] Potential NWAs are subject to a cost-effectiveness analysis as outlined in Commission Rule 4 CCR 723-3-3535.

(1) Pilot Programs

107. Commission Rule 4 CCR 723-3-3533(a)(IV) requires that as a part of any Distribution System Plan, a utility must "accept third-party proposals for pilots and programs at any time" and that when seeking approval for such pilots or programs, "the utility shall provide an overview of all pilots and program proposals considered and an explanation for its proposed selections and rejections." In addition, the 2022 DSP Settlement Agreement required the Company to establish a technical working group to discuss the scope and focus of solicitations for third-party proposals.

(a) Company Direct Case

108. Company witness Beth Chacon testifies that the DSP Technical Working Group met ten times and that these meetings were attended by 58 individuals from 26 organizations. She notes that two of these meetings focused on objectives, areas of interest, potential budgets, required information and other subjects related to DSP pilots. At the suggestion of workshop participants, the Company later held "office hours" sessions with potential proposers to discuss and refine pilot concepts informally. Company representatives met with 15 parties, of which ten ultimately submitted pilot concepts.[114]

[113] Commission Rule 4 CCR 723-3-3534(a).
[114] Hr. Ex. 108, Chacon Direct, pp. 6-9, 16.

109. In the solicitation that the Company ultimately released, it asked for pilots that would achieve one or more of the following seven goals: (1) integrate DERs, NWAs and emerging technologies; (2) improve distribution system performance; (3) minimize distribution system costs; (4) increase distribution system reliability; (5) increase distribution system resiliency; (6) reduce greenhouse gas emissions including from reduced curtailment of renewable energy; and (7) provide benefits to DI Communities. The solicitation also strongly encouraged proposals addressing outage prevention, restoration and resilience; system visibility and control to prepare for a high DER future; increased utilization of distribution capacity; and machine learning and AI to develop novel approaches. Although proposals that did not address these areas of interest were permitted, evaluation criteria included an evaluation of whether proposals addressed one or more of them.[115]

110. Thirty concepts were submitted by 27 organizations. The majority of the submitters were technology companies, but there were also some municipal organizations. After reviewing these concepts, the Company invited formal proposals from seven of them. Once received a Company team reviewed and scored them across pre-established evaluation criteria and then made recommendations for which should move forward.

111. Ultimately, the Company chose not to submit any of these proposals as pilots for a variety of reasons, including that the proposal was duplicative with existing Company programs or commercially available technologies, that the proposal would not be suitable for a utility-focused program or solution, or that the proposal was not reasonably expected to support the distribution system or otherwise result in tangible benefits for customers and communities. Here, the Company references guidance given in the Company's last DSP, which indicated that

[115] *Id*. at 9-10.

pilots should involve either very innovative efforts (research that has not been done elsewhere) or that the Company should be able to make a showing that the value of any hands-on knowledge it will gain from the pilot exceeds the pilot's costs.[116] The Company states that the evaluation criteria helped clarify how well the proposals and the intended outcomes would benefit customers and the distribution system. Additionally, the Company reviewed all its ongoing activities and technology to determine if any proposals were duplicative in purpose or technology to existing efforts.[117]

112. The Company states that in working with stakeholders and going through the pilot development and solicitation process, it learned that the length of the process specified by Rule 4 CCR 723-3-3533(a)(IV) is problematic. The Company contends that including time for contract negotiations, the process would require 1.5-2 years between proposal submission and implementation, which does not allow it to make timely decisions to pilot appropriate technologies or processes for near-term needs. The Company claims that the outcomes of other regulatory proceedings, such as TEP or RES proceedings, impact the Company's distribution planning and needs for the distribution system but that "the lengthy process for DSP pilots is out of step with the timelines resulting from those other proceedings," making it difficult to use pilots to test out possible solutions in a timely and efficient manner. The Company contends that the breadth of the solicitation used in advance of this DSP resulted in many concepts that were not particularly well suited to the DSP, and suggests that any future solicitation should be more narrowly targeted to specific types of pilots and demonstration projects.[118]

[116] *Id*. at 19, referencing Decision No. R23-0080, issued on February 2, 2023, in Proceeding No. 22A-0189E.
[117] *Id*. at 17-20.
[118] *Id*. at 24-26.

113. Although the Company did not propose to implement any of the pilots proposed by third parties, it is proposing to implement two of the proposals it received as "demonstration projects," with cost recovery being requested in the future either through the GMAC or the Renewable Energy Standard Adjustment ("RESA") rider.[119] One of these is a project with Encoord which involves developing models to conduct integrated gas service and electric system simulations to inform least-cost electrification strategies that emphasize NWA and DI Community benefits. The Company states that it chose to move this project forward because "it is an innovative approach to study the specifics around electrification impacts and will inform our strategies around how to look for ways to increase utilization of our distribution capacity while considering disproportionately impacted communities." The Company states that the proposed project involves scenario analysis that takes account of both the electrical system and the gas system to identify areas where the Company should make targeted efforts to promote BE, such as areas that have existing feeder capacity and/or aging gas sub-networks that would otherwise need to be upgraded.[120]

114. The second demonstration project that the Company proposes is a flexible interconnection demonstration in conjunction with Pivot Energy. The Company explains that the objective for this project is to work directly with a developer to refine and gain feedback around the flexible interconnection study process as well as specify and demonstrate the monitoring, control and communications capabilities between Xcel Energy systems and the developer's Photovoltaic Plant Controller. The Company expects that the project will help it refine the flexible

[119] *Id*. at 23-24.
[120] *Id*. at 20-22.

interconnection detailed study process and understand important factors needed for developers to move forward with flexible interconnection.[121]

115. The Company also proposed a TDA pilot in its direct testimony. As this pilot is addressed by the NWA/TDA Settlement Agreement discussed below, it will not be further addressed here.

(b) Party Positions

116. Denver recommends that the Commission approve a smart panel pilot to reduce local demand when substations and feeders are approaching capacity limits. Denver notes that many feeders within the city are already constrained, and that rapid electrification will exacerbate the need for system upgrades. It sees smart panels as a way to maximize utilization of the existing distribution grid, and seeks to demonstrate their value through a pilot. It suggests that such a pilot could be limited to TDAs and NWAs or expanded to include feeders already operating beyond the 75 percent load limit. Denver suggests that the pilot could accommodate a range of operational expectations such as number of events per year, length of events, maximum amount of energy controlled during events, and customer communications. Denver acknowledges that its proposed pilot could be submitted as a bid in the Company's AVPP program, but states that it would like to see a pilot move forward whether or not an aggregator submits such a bid. Finally, Denver recommends that the Company compile and report results from the pilot along with its proposal to continue, expand or terminate the pilot in its next DSP application.[122]

117. Denver recommends expanding the TDA concept so that it couples demand control measures with BE, promotes managed EV charging, and offers controllable smart panels.

[121] *Id*. at 22-23.
[122] Hr. Ex. 701, Fuggetta Answer, pp. 21-25,

Denver argues further that the TDA concept should leverage local knowledge and local initiatives, such as the Gas Planning Pilot Community process created by HB 24-1370, which seeks to avoid expansion of or decommission portions of the Company's gas system. Denver advocates that "[Public Service] should engage collaboratively with local governments on its implementation of TDAs to ensure that it can leverage additional resources and local knowledge, better incorporate development patterns and priorities, or coordinate with community-based organizations and local outreach efforts." It asks the Commission to direct the Company to report on the outcomes in subsequent DSPs, along with any recommendations as to program modifications.[123]

118. Denver states that it supports the Encoord pilot. It recommends that the Commission direct the Company to submit detailed assessments of its pilot efforts in the next DSP, to include lessons learned, future applicability, and how the Company proposes to expand and incorporate a wider use of these concepts moving forward. It recommends further that if the Company does not plan to expand the use of any or all of these efforts, it should explain why it has reached that decision.[124]

(c) Findings and Conclusions

119. As an initial matter, as the Pivot Energy and Encoord pilot programs are likely to provide the Company with valuable insights into one form of flexible interconnection and coordinated gas and electric planning respectively, and because no party expressed opposition to these pilots, we approve these Company proposals.

120. Regarding the smart panel pilot advocated by Denver, we agree that this technology shows promise both in reducing the direct cost of electrification to the consumer and in reducing

[123] Denver SOP at pp. 27-28.
[124] Hr. Ex. 700, Shea Answer, pp. 32-33.

ratepayer costs in general by delaying or avoiding otherwise necessary distribution capital investment projects. We therefore wish to encourage full evaluation of the technology. Accordingly, we direct the Company to work with Denver and other interested stakeholders to develop and propose through the 60/90 Day Notice Process a smart panel pilot program, to be funded through the Market Innovation Fund that was established in the Company's most recent Clean Heat Plan Proceeding (Proceeding No. 23A-0392EG).[125] In developing this pilot, we direct the Company to review the PG&E SAVE program, cited by Denver witness Fugetta,[126] as a potential model. We note that the PG&E SAVE program evaluated both smart panels and distributed energy storage within the program and that similar evaluation may be beneficial here. However, we leave it to the stakeholders to determine how closely to hew to the PG&E model recognizing that PSCo has implemented its own distributed battery program previously.

121. We direct that the smart panel pilot should focus on alleviating non-coincident peak loading on one or more distribution assets that are either the subject of an NWA or TDA, and that implementation of load reduction will ideally be facilitated through the AVPP program based on utility signals to one or more aggregators.

122. We further direct that the pilot evaluate the ability of smart panels to participate in the forthcoming Grid DERMs product with the objective of increasing asset utilization and reducing localized capacity constraints through dispatch based on local distribution system conditions.

123. We further direct the Company to include a report on this pilot in the direct testimony of its next DSP application, which at minimum must include the information required

[125] *See* Proceeding No. 23A-0392EG, Decision No. C24-0397 at ¶¶ 198-199.
[126] Hr. Ex. 701, Fuggetta Answer, p. 23.

by Rule 4 CCR 723-3-3542, as well as the following elements: descriptions of the number and types of distribution assets targeted; the number of smart panels deployed on each targeted asset; the considerations and methodologies used in determining load reduction potential from each participant; the aggregate load reduction target for each asset; the date, time and duration of each event called by the Company to dispatch load reduction from smart panels on each targeted distribution asset; a comparison of expected to actual load reduction on each targeted asset for each event; a summary of feedback received from program participants (which may need to be collected by participating aggregators); lessons learned and recommendations for pilot continuation, expansion or termination based on the pilot experience to date.

(2) NWAs and NWA/TDA Settlement

(a) Company's NWA Direct Case

124. The Company identified 145 major grid development projects (*i.e.*, projects with budgets over $2 million). From this initial set, it removed candidate projects that are needed faster than the Company's ability to contract with and operationalize third party NWAs. The Company states that distribution feeder projects take roughly two years to complete, that bank and transformer projects take three years, and new substations take five years to complete. It therefore screened out major feeder projects within the first three years, bank projects within the first four years, and all substation projects. This is in contrast with the NWA screening process in the prior DSP proceeding, which only screened out projects in the first two years of the Plan, which left 18 potential projects in the 2022 DSP.[127] The Company then removed projects that were addressing end-of-life replacements, which removed two projects. Another was eliminated because it serves heavy industry and the Company had already ordered the substation equipment. Of the

[127] Hr. Ex. 105C, Mino Direct, pp. 89-94.

15 remaining NWA candidate projects, four were eliminated because the risks that the projects were designed to mitigate are predicted to be present for more than two-thirds of a year. The Company justified this screen by stating that NWAs are not as suitable for mitigating needs that are present for extended periods. Finally, the Company eliminated projects serving four critical customers, resulting in a final list of seven NWA candidate projects.

125. Consistent with the settlement agreement in the Company's last Distribution System Plan,[128] the Company proposed to bring forward a targeted demand area ("TDA") pilot to address one or more locations the Company identified as opportunities. These are areas where future capacity constraints are likely in five or more years, and specific mitigation projects to address these constraints are not in the current five-year budget plan. Several of these areas have relatively small overloads, which the Company believes can be solved with targeted DSM or DER deployment.[129] The Company notes that it is planning to use budgets approved in the 2024-2026 DSM Plan to support this pilot, so is not requesting any funding in this Proceeding. It states that it intends to leverage existing DSM programs and DERs to address TDA constraints, and will consider enhanced rebate levels or other enhancements to support the TDAs. The Company states that it will provide updates on this pilot through future DSM status reports.[130]

(b) Answer Testimony

126. UCA criticized the Company's NWA approach for failing to use granular demand response data and failure to consider non-generating resources as potential NWA solutions on the downtown Denver network system, where the export of excess DER generation is prohibited.[131]

[128] Settlement approved by Decision No. R23-0080 in Proceeding No. 22A-0189E.
[129] Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, p. 145.
[130] *Id.* at 146.
[131] Hr. Ex. 602C, Konidena Answer, pp. 81-84.

UCA was also critical of the timing constraints the Company used, suggesting that such constraints should be based on the time needed to implement the NWA rather than the traditional solution. UCA also criticized the absence of cost-benefit analysis for traditional infrastructure vs. NWAs and the failure to quantify the cost of permitting delays, which UCA asserted drive cost and timeline risk.[132] UCA concluded that the Company appears reluctant to trust load management alternatives in the NWA process because it believes customer programs have unique challenges related to customer recruitment, enrollment, and retention. UCA contended that the Company has not shown willingness to consider NWAs that may be deployable within shorter timeframes, stating that the Company excludes many projects from NWA consideration based on assumed lead time constraints without evaluating whether specific resource types could be feasible within the required timeframe. UCA concludes that the Company's restrictive screening methodology, narrow lead-time assumptions, limited planning division participation, and underutilization of DERs, demand-side programs, and permitting engagement all demonstrate a lack of commitment to advancing NWAs, and recommends that the Commission reduce the proposed distribution budget. UCA further recommends that the Commission:

- Reform its NWA screening and procurement frameworks to allow portfolio bids that span multiple technologies, multiple feeders or planning divisions;
- Expand the identification of ratable procurement candidates beyond the five distribution assets currently listed in the DSP plan,[133], especially where distribution risks are low-magnitude and short-duration;
- Develop and apply technology-specific lead time estimates for DR, smart panel control, modular storage, and other fast-deploy alternatives, rather than relying on generic or assumed timelines;
- Track and analyze permitting delays to determine where NWAs could provide timely, lower-cost alternatives in constrained or delay-prone areas;

[132] *Id*. at 88-89, 93-96.
[133] These candidates are presented on p. 82 of Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1.

- Integrate NWA screening by Company's planning division and ensure division-level demand response and DER adoption data is used to identify geographically specific opportunities. [134]

127. With regard to TDAs, UCA expressed concern that the Company has missed out on opportunities by restricting them to anticipated grid constraints between six and ten years in the future. UCA identified 19 TDA opportunities in the GNA in addition to the five TDAs that the Company proposed, all of which are at least 6 years in the future and have no more than 0.1 MW of load at risk for no more than a handful of hours per year. UCA contended that failure to identify viable TDAs in this DSP could have implications for the level of investment in future DSPs, and recommended that the Commission direct the Company to expand the consideration of TDAs to short-term risks, contending that the Company is potentially overlooking cost-effective TDA opportunities.[135]

128. Denver advocates for consideration of building shell DSM measures, thermal energy networks ("TENs"), gas planning pilot communities (pursuant to HB 24-1370), and the Neighborhood Residential Retrofit initiative approved in the Company's most recent clean heat plan proceeding in planning for TDAs and NWAs.[136] With regard to TENs, Denver notes the dramatic reduction in peak load they can provide compared to scenarios involving air-source heat pumps, with concomitant savings in required grid upgrade costs.[137] Like UCA, Denver points out that the Company's NWA screening process eliminates any projects on the Denver network system because a network system cannot accommodate DERs that export generation onto the system. Denver argues that this exclusion is overly broad because 1) it contravenes Commission Rule 3527(f), 2) TENs do not generate power, and 3) the NWA suitability screening process does

[134] *Id*. at 101-102.
[135] *Id*. at 77-81.
[136] Hr. Ex. 701, Fuggetta Answer, p. 13, 18-20.
[137] Hr. Ex. 700C, Shea Answer, pp. 54-63.

not allow for wholesale elimination of any project under the criterion noted by the Company within the "Special Project Screen." Denver therefore recommends that the Commission direct Public Service to conduct an alternatives analysis to assess the potential for a TEN serving the Downtown Denver area to defray infrastructure costs across its energy services when compared to other decarbonized solutions. Denver further recommends that the Commission direct the Company to remove the "Special Project Screen" as it applies to the Network System and assess opportunities to deploy NWAs on the Network System in future DSPs.[138] Denver also asks the Commission to explicitly include TENs and other geothermal technologies as qualifying technologies for NWAs.[139]

129. ACE is highly critical of the Company's NWA process, noting that the process screens out almost all projects, that it requires potential bidders to sign an "extremely problematic" NDA that most will not sign due to unacceptably high exposure to liability, and that the period between request for proposal ("RFP")_ issuance and the response due date is much too short to facilitate meaningful responses.[140] ACE is also critical of the cost-benefit analysis ("CBA") the Company proposes to use, indicating that the proposed analysis is unclear and that some aspects appear to violate Commission rules. ACE recommends that the Commission reject the CBA and require the Company to refile a revised methodology that is consistent with the National Standard Practice Manual.[141] ACE recommends that the Commission direct the Company to (1) eliminate the requirement that companies sign an NDA to view the Grid Needs Assessment with detailed

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[138] *Id*. at 63-73.
[139] Denver SOP at pp. 26-27.
[140] *Id*. at 34-35.
[141] Hr. Ex. 900, White Answer, pp. 10-12; 42-46.

data regarding the potential NWA projects; and (2) implement an informal working group before the issuance of the RFP so that bids can be more successfully crafted to meet grid needs.[142]

130. SWEEP/NRDC is also critical of the major grid development projects screening process, which eliminated nearly 90 percent of projects from NWA consideration, and notes that a similar fraction will be eliminated in the next DSP filing unless the process is changed. SWEEP/NRDC recommend that the Commission require the Company to accept NWA bids that satisfy only a part of the identified grid need, as opposed to the entire need as proposed, and to assemble portfolios of projects to fully satisfy the identified need. SWEEP/NRDC note that the Company's TDA pilot proposes to address only five of the 73 areas where the grid needs assessment indicates a first-year risk beginning five or more years in the future. SWEEP/NRDC recommends that the Commission require the Company to reevaluate TDAs on an annual basis and upgrade TDAs to NWAs if (1) the constraint persists; (2) the implementation timeline becomes less than five years; and (3) if the characteristics satisfy the remainder of the NWA screening criteria. SWEEP/NRDC asks further that the Commission require the Company to select at least five additional TDAs identified in the GNA that are similar to those selected for the Company's TDA pilot and make them available to developers for market-based TDA proposals. SWEEP/NRDC suggest a comparison of market-based and company implemented TDAs could identify which approaches are most cost-effective.[143]

131. AEU shares the concern expressed by other parties that the Company has been overly rigid in its screening process, and that the long lead times of conventional solutions results in potentially viable NWAs being screened out. AEU contends that many of the 35 projects

[142] *Id*. at 46-49.
[143] Hr. Ex. 1400, Alatorre Answer, pp. 27-35.

identified in the grid needs assessment with costs between $0.5 and $2 million could be good candidates for targeted battery-based NWAs. AEU therefore recommends that the Commission require the Company to adjust the NWA and ratable procurements screening criteria to ensure non-conventional alternatives are properly evaluated.[144]

(c) Rebuttal Testimony

132. The Company's rebuttal testimony in this area is largely conciliatory to intervenor comments. Company witness Pollock largely agrees that the NWA process is not working well, and points to process constraints imposed by Commission rules as the source of the problem. He notes Company testimony in the DSP rulemaking (Proceeding No. 20R-0516E) that this process is more litigious than those of other states. Pollock argues that rather than simply creating more NWA opportunities as some parties request, "…we should be amending the process to introduce more flexibility to enhance the prospects of a more limited subset of NWAs (as part of a broader portfolio of non-traditional solutions)." He cites a discovery response by ACE supporting modifying Commission rules to support process improvements. He also cites the requirement that the NWA solicitation must be technology neutral as a constraint, in that it requires the Company to "assume the lowest common denominator when it comes to lead time," preventing a focus on specific technologies that could be deployed more quickly.

133. Pollock notes that the NWA process was modeled on the successful ERP solicitation process, but emphasizes that the Electric Resource Planning process has evolved considerably from its initial creation two decades ago, and that the JTS Proceeding Phase II framework is evidence of further evolution. He states that he considers the party critiques in this case to be evidence that the NWA process needs to evolve as well, and expresses concern that

[144] Hr. Ex. 2101C, Burgess Answer, pp. 80-83, 92.

"failure to adapt a more flexible and rolling process for NWA solicitation and assessment will put us in a perpetual cycle that features a consistent lack of interest and cost-effective NWA bids."[145] Pollock notes that by the time an NWA solicitation is issued, the underlying GNA is two years old, limiting the Company's ability to evaluate NWAs through its annual planning process. He estimates a rolling process could reduce the timing criteria for NWAs by up to a year, driving better opportunities and would offer the following benefits:

- Would allow the Company to pursue NWA opportunities in a more real-time fashion using more up-to-date loading and system data;
- Would enable the Planning team to pursue NWAs as it would any capacity expansion project, allowing planners to lean on their knowledge of the local distribution system to inform NWA opportunities with the highest likelihood of success;
- Would allow the Planning team to understand the severity of the risks in the area and identify which technologies are best suited to meet that need;
- Would provide as much lead time as possible to pursue NWA solicitations, which would allow the Company to reduce the timing criteria by a year, and opening up more NWA opportunities; and
- Would allow the Company more flexibility to incrementally build an NWA portfolio in stages over time and allow bidders to stage or segment implementation of NWAs, an option which is not currently available (consistent with advocacy by SWEEP/NRDC). [146]

134. Pollock responds to many of the individual concerns expressed by the parties, and describes a nine-step "reboot" of the NWA process, and suggests that this reboot is justified by the parties' answer testimony.[147]

135. Regarding TDAs, Pollock states that the recommendations from SWEEP/NRDC and Denver are reasonable and specifically that he supports the SWEEP/NRDC recommendations

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[145] Hr. Ex. 122, Pollock Rebuttal, p. 25.
[146] Hr. Ex. 122, Pollock Rebuttal, pp. 21-28.
[147] *Id*. at 31, 52-57.

and that the Company supports considering a broader number of TDA opportunities. He states that TDAs are a great complement to NWA opportunities and are not subject to some of the same constraints that make NWAs challenging to implement. Pollock also expresses openness to market-based TDA solutions as well as those the Company implements. He states that third-party TDA solutions providers could allow the Company to better understand important attributes such as speed of deployment relevant to traditional solutions, performance characteristics, and cost.[148] Responding to UCA advocacy that the capital budget should be reduced due to its perception of shortcomings in the integration of non-traditional solutions, Pollock argues that capacity projects and non-traditional solutions are not interchangeable. He contends that non-traditional solutions vary considerably in their value and scalability, and that the Company will incorporate their impact into the annual load forecasting process after they have been deployed and their impacts on load and demand are observed.[149]

136. Company witness McDermott responds to Denver's advocacy that the Company's next DSP include an analysis of the potential for an Ambient Loop TEN in downtown Denver. She notes the Company's ongoing support for this concept through Proceeding No. 24A-0369G, and its support for a grant application to study feasibility for a low-emissions district energy system in Denver. While the load from TENs is not included in this DSP, McDermott states that it can be incorporated in future DSPs when TEN plans are sufficiently firm. She asserts that the Company's effort to move toward its 75 percent planning load limit will support any TENs developed in the future by having capacity available to serve them. However, she rejects the notion that the Company should prepare a TEN feasibility study at this point, suggesting that this evaluation

[148] *Id*. at 31-33.
[149] *Id*. at 34-35.

should continue through the other ongoing Commission processes addressing the Denver Ambient Loop, which will be considered in the Company's next Steam Resource Plan due to be filed by November 1, 2028.[150]

137. Company witness David Mino responds to the UCA concern that the NWA timing screen eliminated over 90 percent of major distribution projects from consideration by explaining that there must be sufficient time following the conclusion of Phase II of a DSP proceeding for the Company to complete a mitigation project, in case no NWA solutions are selected. Mino notes that the fact that some NWA technologies could be deployed more quickly is irrelevant, because the NWA solicitations must be technology neutral and in any case, the time to complete the regulatory process must also be considered.[151] Mino also responds to Denver's request that the Company be directed to remove its screen that prohibits NWAs on the Denver network system. Mino states that the purpose of this screen is to reflect the unique nature of the network system, particularly that electricity cannot be exported onto the network and the length of time it takes to construct projects in downtown Denver. He states that non-exporting technologies are permitted, but they are not sufficient to offset load growth.[152]

138. In response to SWEEP/NRDC's proposal that the Company accept NWA solutions addressing only a part of the identified need, Mino suggests that the best solution would be for vendors to develop a combined solution or a joint venture to submit a proposal to completely address the relevant risks. He states that the Company opposes a scenario in which it has multiple contracts with different NWA providers, each of which is responsible for satisfying only a portion of identified needs. He states that a partial solution would not avoid the conventional solution, and

[150] Hr. Ex. 123, McDermott Rebuttal, pp. 19-21.
[151] Hr. Ex. 124C, Mino Rebuttal, pp. 41.45.
[152] *Id*. at 46.

so would not be cost-effective. He further cites problems such as one vendor defaulting while the others perform, or multiple developers contributing to the same NWA cannibalizing customers from each other, which again, could require the Company to accelerate the original infrastructure project while continuing to pay NWA service providers that are performing per their contract.[153]

139. In response to the AEU recommendation that NWAs be considered for projects below the $2 million threshold, Mino states that the Company agrees with this threshold, which is established by Commission Rule 4 CCR 723-3-3572, because of the time, money and effort required to litigate the NWA process. However, he notes that the Company does consider NWAs internally for smaller projects, citing the mobile battery he discusses in his direct testimony.[154]

(3) NWA and TDA Settlement Agreement

140. On August 15, 2025, the Company filed an Unopposed Non-Wires Alternatives and Targeted Demand Areas Settlement Agreement, on behalf of itself, UCA, CEO, Boulder, WRA, AEU, ACE, CRES and SWEEP/NRDC. Staff and Denver did not join, but did not oppose this settlement, and the remaining parties in this Proceeding took no position. The NWA/TDA Settlement Agreement contains the following provisions with regard to NWAs:[155]

- Five of the NWA opportunities the Company identified in its direct case will be advanced provided these projects are not materially altered by the time the Commission issues its final Decision in this Proceeding;
- Additional near-term NWAs may be pursued where distribution risks are low in magnitude and/or short in duration;
- RFPs for the five identified NWAs will be released on a staggered schedule, and proposals will be allowed to offer solutions to multiple NWAs within a single RFP response;

[153] *Id*., at 48-49.
[154] *Id*. at 50. Note that this project would connect a truck-mounted BESS to support overtaxed transformers or feeders.
[155] NWA/TDA Settlement Agreement, pp. 3-6.

- NWA procurement in the future will be modified to have the following general characteristics:
  - rolling solicitations;
  - an annual process aligning with the Company's planning cycle;
  - a portion of existing demand response capacity on each feeder that is part of an NWA opportunity will be incorporated into the load relief requirements as long as it can be dispatched to meet local distribution need;
  - timing screens will be broadened by approximately one year to expand NWA opportunities and allow the Company to evaluate more NWAs than under the current process;
  - the Company is granted license to encourage specific technology types to bid;
  - the Company commits to re-evaluating lead times for DR and other technologies and incorporate these lead times into its planning cycle;
  - the Company commits to considering developer lead time as part of its consideration of NWA opportunities;
- The Company will convene a technical stakeholder working group to present the NWA and TDA opportunities it plans to advance annually following the conclusion of its planning cycle;
  - The Company will provide a preview of its plans at least one week in advance of this meeting;
  - Following the meeting, the Company will file the presentation of opportunities in the most recent DSP proceeding and stakeholders will have 30 days to submit comments on them;
  - Following the comment period, the Company may use a rolling process to release RFPs based on the timing needs for the opportunities;
- The Company will inform the Commission of RFP results through annual follow-on notices filed in the most recent DSP proceeding;
  - The annual notices will indicate whether proposals were received, results of proposal evaluations, and Company decisions on whether to move forward with any proposals;
  - Following each notice filing, there will be a 30-day stakeholder comment period and a 30-day Commission review period;
  - NWA implementation would then commence, absent a directive from the Commission not to pursue any particular NWA.

- Within 120 days of the Commission's final Phase I Decision in this proceeding, the settling parties will convene and finalize a proposal to develop additional details for the updated, rolling NWA process, including methods to integrate bids that solution for multiple NWA opportunities;
- The Settling Parties agree to support or take no position on any Company requests for waivers or variances of Commission Rules necessary to modify the NWA process consistent with the updated, rolling NWA process;
- The rolling NWA process will be evaluated in a future filing, such as a DSP, and the Settling Parties reserve the right to take any position on the process at that point.

141. The NWA/TDA Settlement Agreement contains the following provisions regarding TDAs:[156]

- The Company shall carry out annual tracking and reevaluations of TDAs, including identification of locations with relatively small overloads or low-magnitude, short-duration constraints where TDAs could defer or avoid longer-term conventional upgrades or grid needs;
- The Settling Parties support, and the Company agrees to, increase the number of TDAs;
  - The Company will work with the Settling Parties to identify additional TDA opportunities in appropriate future proceedings, with priority given to projects in areas with small overloads or low-magnitude, short-duration constraints.

142. All testimony filed regarding the NWA/TDA Settlement Agreement was supportive of the above terms.

(4) Findings and Conclusions

143. The Commission shall approve a utility's investment in NWAs, pilots, or programs if the Commission finds the investment to be in the public interest.[157] In considering whether the investment is in the public interest, the Commission shall determine whether the utility's ratepayers realize benefits from the NWA, pilot, or program and whether the associated costs are just and

[156] *Id*. at 6-7.
[157] Rule 4 CCR 723-3-3538(c).

reasonable. The utility may seek approval to implement NWAs, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation.[158] Further, pursuant to § 40-2-132.5(5)(d)(VI), C.R.S., the Commission shall consider whether the DSP contains proposed actions to facilitate programs for: (A) The competitive acquisition of cost-effective non-wires alternatives to defer or avoid identified system distribution infrastructure projects, subject to investment thresholds in commission rules; (B) Load and generation flexibility, including interruptible programs, with due consideration given to programs proposed or approved in other commission proceedings; and (C) Other alternatives to system upgrades, which may include automated distributed resource management systems.

144. When considering a settlement agreement, the Commission has an independent duty to determine matters that are within the public interest. *See Caldwell v. Public Utilities Commission*, 692 P.2d 1085, 1089 (Colo. 1984). The Settling Parties have the burden of proving by a preponderance of the evidence that the settlement agreement is just and reasonable and in the public interest.

145. The Commission applies these principles and legal standards here to assess the NWA/TDA Settlement, and finds the NWA/TDA Settlement in the public interest. We find that the provisions of the NWA/TDA Settlement Agreement are likely to address many of the shortcomings the parties identified with the existing process, and are likely to foster both a greater number of viable proposals in response to NWA solicitations and higher quality proposals. While the NWA/TDA Settlement Agreement's provisions regarding TDAs are sparse, we find that the proposed annual cadence and commitment to engage with the Settling Parties are likely provide improvements to the existing process, resulting in a greater number of TDAs, and therefore provide

[158] Rule 4 CCR 723-3-3538(c).

greater opportunity to postpone or entirely avoid distribution capacity projects. Accordingly, we approve the NWA/TDA Settlement Agreement.[159]

146. We further find Denver's recommendations regarding the potential inclusion of demand response measures in TDAs, collaboration with local government initiatives such as the Gas Planning Pilot Community, and reporting on the outcomes of its TDA efforts to be friendly amendments to the NWA/TDA Settlement Agreement. We therefore expect that in implementing TDAs, the Company will emphasize managed EV charging and demand response measures rather than relying solely on end-use efficiency; and that it will leverage the expertise and efforts of local governments in designing and implementing TDA approaches. We also direct the Company to include thorough reporting on its TDA efforts in its next DSP Application along with its recommendations for any modifications in its approach to TDA implementation.

147. We find Denver's concerns regarding the Company's blanket prohibition of NWAs from the downtown Denver network system to be completely justified. There is no basis in the rules for this prohibition, and while a prohibition against exporting generation onto the network may be justified from a technical standpoint, Denver is correct that there are many potential forms of NWAs that either do not generate or that would not export excess generation of behind-the-meter assets. Accordingly, we direct the Company to remove its blanket prohibition of NWAs from the Denver network system and replace it with a screen that appropriately limits or prevents the export of generation from any equipment installed as part of an NWA where that is necessary from a technical standpoint.

[159] Concurrent with its DSP Application, the Company filed its Omnibus Motion in which it requested a Partial Variance from Rules 3528(c) and 3527(b)(VI). To the extent this variance is necessary to effectuate the NWA/TDA Settlement, we find good cause to grant the motion.

148. Finally, with regard to Denver's request that the Commission direct the Company to include TENs and other geothermal technologies as eligible for NWAs, we find that Rule 4 CCR 723-3-3527(f) establishes a sufficiently broad definition of "DER" such that these technologies are already viable contributors to NWAs. While TENs are not listed in Rule 3527 the rule states explicitly that the definition is not limited to the technologies that are listed. TENs and other geothermal technologies must be considered viable candidates for inclusion in TWAs.

4. Non-Capacity Investment

a. Company's Direct Case

149. Public Service proposes a total of $1.678 billion in non-capacity distribution investments over the 2026-2028 period, split into the following categories: Asset Health and Reliability, Tools and Communications, Mandates and New Business. Asset Health and Reliability is the largest non-capacity investment category, representing 61 percent of the total. The Company indicated that undergrounding of above-ground feeders is conducted through three programs: through the Targeted Undergrounding program, a sub-category to Asset Health and Reliability (*i.e.,* of lines with frequent weather-related outages);[160] through the Mandates category of investment (*i.e.*, required by communities the Company serves);[161] and, through the New Business category of investment.[162] Recent historical, current year (2025) and proposed expenditure levels are presented in the table below:[163]

[160] Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, p. 96.
[161] Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, p. 99.
[162] Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, p. 100.
[163] Derived from Hr. Ex. 101, Ihle Direct, Figure ES-5; Hr. Ex. 109, Completeness Information, p. 7.

DSP Budget ($M)	2023	2024	2025	2026	2027	2028	Total 2026-2028
Capacity	100	122	289	413	478	472	1,363
Non-Capacity							-
Asset Health & Rel.	209	225	286	320	342	364	1,026
Tools & Comms	16	20	13	13	16	17	46
Mandates	49	51	53	54	55	56	165
New Business	135	190	132	137	145	159	441
Total Non-Capacity	409	486	484	524	558	596	1,678
Total GMAC-related Distr. Expenses	509	608	773	937	1,036	1,068	3,041

150. Public Service explains that Asset Health and Reliability investments are related to infrastructure that is reaching the end of its useful life or is experiencing higher failure rates – and that, as a result, will negatively impact reliability of service.[164] The Company proposes Asset Health and Reliability spending of approximately $1.026 billion over the 2026-2028 period, or $340 million per year, across ten sub-categories. Proposed spending – along with historic and current year (2025) spending – is presented in the following table:[165]

Asset Health & Reliability Budget ($M)	2023	2024	2025	2026	2027	2028	2026-2028 Total
Asset Ren. - Discretes - Lines	10	6	-	-	1	2	3
Asset Ren. - Disc. - Substations	1	5	4	9	8	8	25
Cable Repl. and Assessment	46	60	66	67	69	71	207
Failure Reserves	9	15	22	23	16	19	58
Line Asset Renewal Programs	3	2	18	16	16	16	48
Pole Replacements	19	14	51	52	54	34	140
Routines	94	82	83	86	89	93	268
Substation Asset Renewal Progs	18	27	29	46	58	61	165
Targeted Undergrounding	-	-	-	8	16	42	66
Emergent Asset Health	8	13	14	14	14	18	46
Total Asset Health & Reliability	208	224	287	321	341	364	1,026

151. The Company's proposed Asset Health and Reliability spending levels are roughly 60 percent higher than expenditure levels as recently as 2023. The increase is largely associated

[164] Hr. Ex. 106, Bloch Direct, p. 9.
[165] Hr. Ex. 106, Bloch Direct, Table KAB-D-1 and Hr. Ex. 109, Completeness Filing, p. 8.

with the Company's new Targeted Undergrounding program ($64 million proposed over the 2026-2028 period), the Substation Asset Renewal Program ($165 million), and the Line Asset Renewal Program ($48 million). At hearing, the Company explained that the increased investment is necessary to keep up with significant equipment cost inflation experienced in recent years.[166]

152. The Company notes that examples of Asset Health and Reliability 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.[167] This category also captures asset replacements due to storms. The Company argues that the projects proposed under the Asset Health and Reliability category of spending "fit with the legislation's definition, which specifically includes the general category of 'repair and replacement programs' as well as the more specific categories of conductor replacements, pole repair and installation, overhead replacement, defect corrections, and major line rebuilds."[168]

b. Answer Testimony

153. UCA proposes a 14.7 percent reduction in the Company's proposed Asset Health and Reliability spending (representing $252 million through 2029) due to claims of redundant spending or lacking a cost-benefit analysis or performance-based justification.[169] UCA recommends specific adjustments and reasons to Asset Health and Reliability sub-categories including: Failure, or Transformer, Reserves (25 percent reduction) due to the budget "not sized in proportion to system-wide risk and instead reflects a generalized contingency category;"[170] Pole replacements (20 percent reduction) due to arguments the Company is installing stronger

[166] Hr. Tr. August 28, 2025, p. 304:12-16.
[167] Hr. Ex. 106, Bloch Direct, p. 9.
[168] *Id.*
[169] UCA SOP at pp. 17-18.
[170] Hr. Ex. 602, Konidena Answer, p. 104.

poles which will reduce the need for future replacements and no measurable improvement in reliability;[171] Routines (20 percent reduction) due to UCA's claim the Routines budget lacks prioritization, asst condition scoring and risk thresholds, and that the Company provided no metric for measuring the associated resiliency benefits;[172] Emergent Asset Health (25 percent reduction) due to lack of data on how frequently such large emergent projects arise and that the Company offered no examples where such projects led to measurable improvements in reliability or resiliency metrics;[173] and, Targeted Undergrounding (50 percent reduction) because the Company has not given its other programs such as Pole Replacements or Routines time to demonstrate their full impact on system performance (as stronger poles should reduce storm outages),[174] and as there may be substantial overlap with the WMP.[175]

154. UCA recommends that the Company "create and provide an initial comprehensive study and report regarding its undergrounding plan in this proceeding as well as the WMP," which; a should include: a) Total amount of miles to underground each year of the plans' implementation; b) Cost-benefit analysis of the selected undergrounding infrastructures; c) identification and mapping of the selected undergrounding infrastructures; d) programmatic schedule for undergrounding activities by year; e) amount of poles substituted by undergrounding; and f) total amount of yearly estimated capital expenditures on undergrounding across the Company's programs.[176]

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[171] *Id.* at 105-106.
[172] *Id.* at 107.
[173] *Id*. at 113.
[174] Hr. Ex. 602, Konidena Answer, p. 112.
[175] UCA SOP at p. 6.
[176] UCA SOP at p. 4.

155. CEO groups Targeted Undergrounding with the other undergrounding activity (discussed below) including mandates and new business and suggest the need for guardrails and information about when undergrounding projects are or should be pursued. CEO suggests four recommendations: (1) Public Service should adopt a rubric when an underground activity affordably and strategically benefits or advances the targets, standards, plans, regulations, and State energy policy goals;" (2) that the Company's next DSP include a comparison of how the underground distribution activities perform compared to overhead distribution activities, and that the comparison include a quantitative analysis of the increased reliability and resilience provided by undergrounded equipment; (3) that the Company provide in the next DSP SAIDI, SAIFI, and Customer Average Interruption Duration Index (CAIDI) metrics for poor performing feeders, substation transformers, and substations identified in the Company's QSP; and (4) that the Company "identify proposed distribution activities that are projected to improve reliability issues of poor performing assets and whether or not they are located in or directly serve Disproportionately Impacted Communities."[177]

156. Staff also raises concerns regarding targeted undergrounding and the Company's proposed "full discretion over the lines to underground" which it says raises questions about cost control, equity, and transparency.[178] Staff notes the Company has not provided a specific list of criteria for the power lines it plans to underground; instead, only general guidelines have been offered. Staff recommends the Company be required to provide the following before embarking on any targeted undergrounding: A detailed cost estimate of targeted undergrounding to including capital and O&M costs, broken down by segment (trenching, equipment, labor, permitting, where applicable); a

[177] Hr. Ex. 401, Gegner Answer, pp. 6-7.
[178] Hr. Ex. 501, Abiodun Answer, p. 10.

ranking of all overhead lines that are candidates for undergrounding according to the frequency and impact of outages on ratepayers and business where such lines are located using a range of metrics; a cost-benefit analysis of the selected lines including the quantification of avoided outage costs; and a comparative analysis of targeted undergrounding against other measures such as vegetation management and covered conductors.[179]

c. Rebuttal

157. Public Service argues the budget reductions UCA recommends are arbitrary and not supported by any particular set of criteria or objective standard and could impede the Company's ability to respond necessary corrections leading to outages that could have been avoided or mitigated by quick response.[180] Regarding Failure Reserves, Public Service argues that maintaining a sufficient supply of mobile substation equipment allows the Company to restore service in the time it takes to deploy, connect, test, and energize the mobile unit—typically about 24-72 hours (this range is due to weather, topology such as mountain regions, and configuration of the substation and the mobile unit).[181] Permanent repairs or replacements of substation transformers often take weeks to months to complete, and procurement lead times for substation transformers have increased significantly over the last several years, making a reserve supply of transformers critical to the Company's system resiliency. Lead times that were in the range of 10-18 months just a few years ago are now typically 30-48 months, resulting in longer timelines to plan a replacement for equipment once the replacement decision is made. Further, Public Service

[179] Hr. Ex. 501, Abiodun Answer, pp. 16-17.
[180] Hr. Ex. 125, Bloch Rebuttal, p. 9.
[181] Hr. Ex. 125, Bloch Rebuttal, p. 11.

argues, that a transformer can fail without resulting in customer outages does not mean that those transformers were unnecessary. Rather, it demonstrates the benefits of redundant system design.[182]

158. With respect to Pole Replacement, Public Service notes that in 2014, the Company moved from NESC Grade C to Grade B as the standard for all new and rebuilt distribution poles (incorporated by reference as Colorado law), representing a 50 percent stronger pole.[183] However, contrary to UCA's suggestion, if poles are allowed to remain without inspection until they fail, there is a risk of bystander or worker injury due to a pole collapse or live wire scenario as well as risk of property damage to homes or other structures. Further, SAIDI and SAIFI cannot fully capture the improvements pole replacements bring to the system because (1) outages resulting from events outside the Company's control, like storms or a car crashing into a pole, are intentionally excluded from those metrics, (SAIDI and SAIFI are intended to demonstrate the resilience of the system under normal conditions) and (2) those metrics do not provide a way to quantify the value of replacing a pole before it fails, nor can they quantify the safety aspect of this program for Company linemen and the public.[184] The decision to move to Class B poles was made a decade ago - it would be inappropriate to now impose a requirement to complete a cost benefit analysis of a program that has already been implemented for such a long period of time. With respect to concerns of overlap, Public Service states the Pole Replacement program budget is for those poles identified through the cyclical assessment process, which is monitored and tracked, making it unlikely that a pole marked for replacement under the Pole Replacement program would be allocated to another budget category. Regarding the benefit of the pole replacement, Public Service admits it is possible poles will last longer and fewer poles will need

[182] Hr. Ex. 125, Bloch Rebuttal, p. 13.
[183] Hr. Ex. 125, Bloch Rebuttal, p. 15.
[184] Hr. Ex. 125, Bloch Rebuttal, p. 17.

to be replaced in the future, but the Pole Replacement program only inspects poles that are ten years old or older and is moving to a 12-year replacement cycle incorporating the need to replace fewer poles going forward.[185]

159. Similarly, with Routines, the Company disagrees with UCA's claim the Company's budget lacks prioritization and says – by its very nature – Routines are intended to capture unplanned but common types of repairs that individually "would not make sense to evaluate them" as UCA suggests.[186] Public Service further contends that reliability metrics like SAIDI and SAIFI do not capture the full benefit of Routine activities, and that while improvements in pole standards could ultimately reduce the cost of Routine activities, that is a mere hypothetical and does not accurately reflect circumstances in the next five years."[187]

160. With respect to Targeted Undergrounding, Public Service argues while the term "targeted undergrounding" is used in both DSP and WMP proceedings, they are two distinct initiatives designed to accomplish unique goals. For WMP undergrounding, the Company will select distribution systems to underground specifically with the aim of reducing the risk of wildfire.[188] For the Asset Health and Reliability Targeted Undergrounding, the Company will select overhead lines based on a history of frequent weather-related outages. Public Service also notes that the program is new and the Company is taking a deliberate approach to developing all aspects of the Targeted Undergrounding program including identifying the lines most in need and developing an effective communication plan to increase the likelihood of property owner buy-in before substantial investments are made.[189]

[185] Hr. Ex. 125, Bloch Rebuttal, p. 19.
[186] Hr. Ex. 125, Bloch Rebuttal, p. 22.
[187] Hr. Ex. 125, Bloch Rebuttal, p. 23.
[188] Hr. Ex. 123, McDermott Rebuttal, p. 14.
[189] Hr. Ex. 125, Bloch Rebuttal, pp. 24-25.

161. Public Service argues there is no risk that the Company will spend duplicative construction resources undergrounding the same line under both of the targeted undergrounding programs. The Company coordinates its planning and will not select the same lines for undergrounding in two different programs.[190] Public Service also notes that the Targeted Undergrounding will be identified in the budgets in each DSP and will provide the program prioritization factors. The Company also raises concern that the Staff, UCA, and CEO proposals are "unnecessarily cumbersome and would create unreasonable barriers to completion of the important Targeted Undergrounding work that needs to be done" though it will consider the categories of information the parties, especially Staff witness Abiodun, identified when it is developing its method for identifying lines to be undergrounded.[191]

162. Public Service explains it intends to use the Customer Experiencing Long Interruptions ("CELI") as the primary initial criteria for identifying locations of lower service quality with consideration also given for long durations. The Devices Experiencing Multiple Interruptions ("DEMI") metric will be used to identify candidate line sections with high historical vegetation and weather-related fault rates.[192]

163. With respect to UCA's claim of lack of integration with the MEP, the Company responds that the modeling and development of the capacity projects in this DSP were completed prior to the completion of the electric infrastructure study that was conducted as part of the Company's MEP.[193]

[190] Hr. Ex. 123, McDermott Rebuttal, p. 15.
[191] Hr. Ex. 125, Bloch Rebuttal, pp. 37-38.
[192] *Id*. at 37.
[193] Hr. Ex. 123, McDermott Rebuttal, p. 16.

d. Findings and Conclusions

164. The Commission agrees with Public Service that UCA's adjustments were generally arbitrary and not tied to any specific calculation. Except for the Targeted Undergrounding program expenditure, which we discuss below, we find the Company reasonably supported its need for the proposed non-capacity investments presented in this Proceeding. We note the Company is responsible for maintaining the reliability of the distribution system for the benefit of its customers. While we discuss below that the application of the GMAC statutory framework required by § 40-2-132.5(7)(b), C.R.S., ultimately requires denial of GMAC recovery for the Asset Health and Reliability category, we otherwise approve the budget as part of the DSP plan. Under these circumstances, Asset Health and Reliability investments made pursuant to this DSP may be recovered as appropriate through ordinary processes subject to after-the-fact prudency review and given the Commission's overriding concern to maintain affordable electric rates. Ultimately, we find it critical to ensure the investments receiving extraordinary cost recovery through the GMAC are providing the asserted benefits of improved reliability, resiliency and overall customer experience, and are strategically and affordably advancing statutory objectives as discussed below.

165. That being said, we find merit with UCA's concern regarding potential overlap amongst and across DSP categories and other programs. With respect to the Company's proposed Asset Health and Reliability spending, we find the distinction between ten separate sub-categories, as presented by Public Service, to lack the transparency necessary to proceed without further checks and balances. Accordingly, we require the Company during the GMAC review and authorization filings in 2026 and beyond to catalogue all proposed and completed investment, as applicable. The filing should facilitate oversight of the Company's investment activities by clearly

and concisely indicating the number of poles, feeder-miles and other statistics of planned and accomplished grid improvement and associated dollars for the DSP and other funding programs of distribution investment including but not limited to the WMP, TEP, and MEP. We delve into this further under "Annual Reporting" section below.

166. Given our affordability and longer-term rate impact concerns, the budgets under consideration here should generally be viewed on a not-to-exceed basis, with the hope that actual capital spending is significantly lower.

167. With respect to the Company's various undergrounding activities, UCA suggested the Commission require the Company to file an initial report on its various undergrounding activities.[194] Staff and CEO suggested similar reporting requirements. We generally adopt UCA's analysis recommendations and require it to be submitted as part of the Company's April 2026 GMAC submission, or earlier under separate cover, including an initial benefit cost analysis on the array of targeted undergrounding projects proposed.

5. Other Aspects of DSP

a. Labor Analysis

168. SB 24-218 requires a utility to provide a detailed analysis of its current qualified staffing level and future required qualified staffing level for each job classification needed to achieve the policies and requirements of the legislation. The analysis of workforce needs must include review of both the anticipated needs of future utility employees as well as the anticipated needs for workforce acquired through third-party utility and construction contractors. Adequate staffing includes engineering and programming staff necessary to oversee the timely

[194] *See* UCA SOP at p. 4.

interconnection of distributed energy resources, energization of electrified end uses, and energization of new service connections to the qualifying retail utility's distribution system.[195]

169. In this DSP, the Company provided a staffing analysis as JJP-5C in which the Company requests Commission approval to add incremental full-time equivalents of 117 people, including potential employees in operations, IT support, Integrated System Planning and modeling, community relations, regulatory, revenue requirements, and forecasting.[196]

170. Staff argues that the Company's staffing analysis is inadequate because it confirmed that the Company "did not analyze the current staffing levels anticipated to achieve policy requirements."[197] Staff argues that without this foundational information, the Commission is unable to "meaningfully evaluate the reasonableness of the Company's DSP labor costs, and this lack of transparency impairs the Commission's ability to exercise effective regulatory oversight." Staff suggests that the Commission should require Company to provide analysis of current staffing levels as part of next DSP compliance filing.[198]

171. ACE suggests that the Commission should require Company to report on new staff hired, with more information about actual job functions and the role those staff play in improving interconnection process. Ultimately, ACE supports increased staffing, but states it remains unclear whether the proposed staffing level will be able to address interconnection delays and lack of customer service for interconnection customers.[199] ACE also suggests additional reporting on staff.

[195] § 40-2-132.5(5)(f)(I), C.R.S.
[196] Hr. Ex. 107, Peuquet Direct, pp. 19:6-23:5.
[197] Staff SOP at p. 28.
[198] Staff SOP at p. 28.
[199] ACE SOP at pp. 22-23.

172. Within a DSP proceeding, the Commission shall consider whether a utility has adequate qualified staffing needed to achieve the policies and requirements of SB 24-218.[200] We find that the Company has largely complied with the requirements set forth in § 40-2-132.5(5)(f)(I), C.R.S. to provide a staffing analysis, however, additional information would be more helpful to ensure that the Commission can consider whether it has adequate qualified staffing needed to achieve the policies and requirements of the DSP statute. Therefore, we agree with Staff and ACE that additional reporting would be beneficial. Future reporting including staffing analyses should also include Capital/O&M splits, similar in form to how the Company presented anticipated labor in Attachment JJP-5C.

b. Performance-Based Framework

173. The Commission shall consider whether the DSP includes proposed, unless already informed or satisfied by Commission rules, standardized, quantifiable, and transparent processes and timelines within the planning period for formal load and generation interconnection and energization requests, so long as the qualifying retail utility is not required to include energization timelines as part of its first distribution system plan filed after May 22, 2024.[201]

174. While we discuss the proposed performance-based framework in greater detail in the "GMAC" section below, we ultimately find that the Company has not provided a workable framework for a performance-based framework for interconnection timelines. Further, the Company did not provide a "general target-setting framework" that could be evaluated in this first distribution system plan filed after May 22, 2024 as required by § 40-2-132.5(5)(e)(III)(A), C.R.S. This deficiency in the Company's filing provides another reason to require the follow-on process

[200] § 40-2-132.5(5)(f)(II), C.R.S.
[201] § 40-2-132.5(5)(d)(V), C.R.S.

discussed in Section J below to ensure that the Company has a performance-based framework contemplated by the DSP statute in place as we look towards its next DSP filing. The Commission also anticipates this to be a large focus of the rulemaking required by § 40-2-132.5(6), C.R.S.

c. Existing DSP Review

175. The Commission's DSP Rules require that a utility present an assessment of lessons learned from the DSP process as well as in a utility's second DSP, a description of past implementation of NWAs, a review of the NWA cost benefit analysis methodology used, as well as proposed performance metrics and benchmarks to track successful implementation of the plan.[202]

176. The Commission shall consider whether the DSP includes documentation demonstrating progress toward implementation of previously approved distribution system plans when evaluating a utility's DSP filing.[203] We find that the Company has provided testimony throughout this Proceeding addressing aspects of progress towards implementation of its 2022 DSP.

d. Infill Housing

177. The Commission shall consider whether the DSP includes a process to identify and evaluate infill housing loads.[204] We are not aware of any portion of the DSP filing that identifies infill housing loads directly, though the Company's plan overall includes consideration of expanding capacity related to and forecasting of both greenfield development and infill housing.[205] While the Company's DSP does not address this statutory criteria directly, we are satisfied that the

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[202] Rule 4 CCR 723-3-3542(c) and (d).
[203] § 40-2-132.5(5)(d)(VIII), C.R.S.
[204] § 40-2-132.5(5)(d)(IV), C.R.S.
[205] *See e.g.,* Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, p. 145.

Company’s DSP considers expanded needs related to new growth as well as increased growth in existing communities.

6. Consideration of Overall DSP Plan

178. Pursuant to § 40-2-132.5(5)(d), C.R.S., the Commission shall evaluate whether the distribution system plan: (I) Establishes a long-term distribution system plan, which must cover at least five years, that includes timelines and budgets to create sufficient hosting capacity across the qualifying retail utility's electrical distribution system to affordably and reliably support the implementation of the applicable targets, standards, plans, and regulations described in subsection (5)(a) of this section; (II) Includes the identification of specific distribution investments needed to strategically support the applicable targets, standards, plans, and regulations described in subsection (5)(a) of this section over the planning period, which must cover at least five years, with increased specificity in the first two years of the planning period; (III) Includes detailed mapping of distribution hosting capacity with appropriate safeguards to protect critical infrastructure, as determined by the Commission; (IV) Includes a process to identify and evaluate infill housing loads; (V) Includes proposed, unless already informed or satisfied by commission rules, standardized, quantifiable, and transparent processes and timelines within the planning period for formal load and generation interconnection and energization requests, so long as the qualifying retail utility is not required to include energization timelines as part of its first distribution system plan filed after May 22, 2024; (VI) Includes proposed actions to facilitate programs for: (A) The competitive acquisition of cost-effective non-wires alternatives to defer or avoid identified system distribution infrastructure projects, subject to investment thresholds in commission rules; (B) Load and generation flexibility, including interruptible programs, with due consideration given to programs proposed or approved in other commission proceedings; and

(C) Other alternatives to system upgrades, which may include automated distributed resource management systems; (VII) Includes adequate reporting and system mapping to implement the proposed plan and programs, as well as: . . . (VIII) Includes documentation demonstrating progress toward implementation of previously approved distribution system plans. We consider these requirements throughout this Decision, but ultimately find that the Company's proposed DSP, as modified by this Decision and the approved settlement agreements, is approved. While the Company has a long way to go, we are overall encouraged by the progress made here towards proactive planning and greater utilization of non-traditional resources.

E. AVPP Application

1. Background

179. Pursuant to SB 24-218, the Company must file an application to implement a VPP program, including a tariff for performance-based compensation for a qualified VPP. SB 24-218 sets forth several requirements for the VPP program, including that it must set a cap for individual resource capacity and minimum aggregation capacity, have requirements for a standard tariff or tariffs to set performance requirements and performance-based compensation for the DER aggregator, have streamlined and reasonable data requirements, and prescribe the method for setting performance-based compensation.[206] On this last point, the statute directs: To the extent applicable, the performance-based compensation methodology must reflect the full value of services, which may include:

(A) Local and system peak demand reduction;
(B) Clean peak service;
(C) Voltage support and other ancillary services;

[206] § 40-2-132.5(8)(b), C.R.S.

(D) The avoidance or deferral of electric or gas transmission or distribution upgrades or capacity expansion;

(E) Locational value as revealed by a grid needs assessment or participation in non-wires alternatives identified in the qualifying retail utility's distribution system plan;

(F) The use of telemetry for settlement; and

(G) Other functions that the commission determines are supportive of efficient planning and operation of the electrical grid.[207]

180. A VPP program "must allow a qualifying retail utility to serve as a DER aggregator so long as the tariff or access to necessary data does not provide the utility a competitive advantage over third-party aggregators."[208]

181. In its Direct Testimony, Public Service proposed a VPP program that it argues is consistent with the requirements of SB 24-218. The Company explained that its proposed VPP program offers aggregators of DERs performance-based compensation for VPP capacity during specified events, the Company's Distributed Energy Resource Management System ("DERMS") facilitates the necessary communications and control strategies, and the Company compensates DER aggregators quarterly based on the average performance of the aggregated group of DERs during all events called in each three-month period.[209]

182. In its Direct Testimony, Public Service stated that it plans to participate as a VPP aggregator. Public Service argued that the Company "has a long history of effective demand management programs, which provides an excellent foundation for the successful enrollment of additional customers into this new offering."[210] Regarding the performance-based compensation, Public Service initially planned to allow and compensate up to an incremental ten percent of an aggregator's committed capacity and allow no more than a 20 percent deviation. For the specific

[207] § 40-2-132.5(8)(b)(XI), C.R.S.
[208] § 40-2-132.5(8)(b)(XII), C.R.S.
[209] Hr. Ex. 117, Pollock Direct Rev. 1, Att. ZDP-1, Rev. 1, p. 3.
[210] Hr. Ex. 118, Erwin Direct, Rev. 1., pp. 17-18.

resource aggregation that has failed to meet the performance threshold, the Company proposed that aggregators be required to pay liquidated damages.[211]

183. Numerous intervenors proposed modifications to the Company's proposed VPP program. One of the most contested issues was whether the Company should be allowed to participate as an aggregator, which Staff, AEU, and ACE all opposed. For instance, Staff argued there are multiple ways the Company could use its role as a regulated monopoly to gain an unfair competitive advantage, including by using the monopoly parts of the business to subsidize the products or services that are competing in the market with unregulated businesses.[212]

184. Several intervenors also objected to the Company's performance requirements for VPPs, the parameters of VPP dispatch events, and the appropriate level of compensation for VPP performance. ACE, for example, argued that the Company's proposed VPP program borrows too heavily from the Company's large-scale resource procurement process and that concepts like liquidated damages are inappropriate for VPPs.[213] ACE argued that to produce the highest quantity of dependable, cost-effective VPPs, one must consider not only how each offered MW performs but also how many MW are offered.[214] ACE and other intervenors argued that the Company's VPP program would likely chill participation. In contrast, UCA argued for an entirely different compensation framework built around a competitive solicitation. UCA argued the Company should acquire VPPs through a competitive solicitation from the outset of the VPP program. Under UCA's approach, competitive bidding would determine the market value of both ERP-type

[211] Hr. Ex. 117, Pollock Direct, Rev. 1, pp. 41-42.
[212] Hr. Ex. 503, Fielder Answer, p. 14.
[213] Hr. Ex. 902, Lucas Answer, p. 14.
[214] Hr. Ex. 902, Lucas Answer, pp. 16-17.

capacity and distribution value and the cost of providing that capacity. UCA argued that competitive bidding will also prevent the Company from overpaying for VPPs.[215]

185. The VPP Settlement filed on August 15, 2025, is comprehensive in that it is intended to resolve all of the many issues the Settling Parties raised during the Proceeding.[216] As set forth above, only UCA and Mr. Althouse oppose the VPP Settlement.

186. The VPP Settlement modifies several components of the Company's initially proposed VPP program. For example, the VPP Settlement prohibits the Company from acting as an aggregator for the first 24 months of the program. After that, the Company would need to request authorization to act as an aggregator in a future Commission proceeding. [217] In addition, the VPP Settlement establishes compensation levels for the first two years of the VPP program and establishes the primary performance requirements and the parameters of the VPP dispatch events. For instance, the VPP Settlement reduces the number of annual VPP events for year-round resources from 100 to 80, sets a maximum duration of four hours for each VPP event, and commits the Company to make best efforts to provide 24 hours' notice prior to VPP events. The VPP Settlement recognizes, however, that the Company may need to call VPP events with a minimum of one hour notification but allows for aggregators to exempt from their annual performance calculation up to five less-than-24-hours'-notice events per year.[218]

187. More generally, the VPP Settlement establishes a standard offer framework in which any eligible aggregator can receive set compensation for VPP services pursuant to the agreed upon tariff on a first-come-first-served basis until the 25 MW/year limit is met.

[215] Hr. Ex. 603, Neil Answer, pp. 40-41.
[216] Hr. Ex. 131, VPP Settlement, p. 2.
[217] Hr. Ex. 131, VPP Settlement, ¶ 20.
[218] Hr. Ex. 131, VPP Settlement, ¶ 14.

The Company set this 25 MW/year cap based on the requested $79 million budget, which would be allocated over five years. After the VPP program has operated for two years, the Company will propose a competitive solicitation of 5 MW of VPP capacity. The Company agrees that it will not seek to participate in this competitive solicitation as an aggregator.[219] To the extent that the Company proposes to participate as an aggregator after the first 24-months of program operation, the Company will bring forward a proposal in the next DSP (or other relevant proceeding) that more clearly documents firewall and other processes to address competitive issues and recovery of costs associated with the Company's participation as an aggregator.[220]

188. The VPP Settlement also expands the Company's reporting requirements regarding the VPP program, requires Public Service to file a compliance advice letter incorporating the various changes to the VPP program, and establishes a pre-compliance advice letter stakeholder process to refine various outstanding issues. These issues include baseline calculations, program terms and conditions, and possible modifications to the grid charging window for VPP resources.[221] The Company further commits to initiate another "operational phase" stakeholder process by July 1, 2026, to address issues such as the need for single-feed aggregation limits and engineering solutions to better accommodate individual DERs up to one MW in size.[222]

189. The VPP Settlement establishes that after the VPP program has operated for two years, the Company will file an evaluation advice letter.[223] This evaluation advice letter will generally include the Company's proposal to continue, modify, or discontinue the VPP program. Among other things, the evaluation advice letter will specifically address whether to include an

[219] Hr. Ex. 131, VPP Settlement, ¶ 10.
[220] Hr. Ex. 131, VPP Settlement, ¶ 20.
[221] Hr. Ex. 131, VPP Settlement, pp. 12-13.
[222] Hr. Ex. 131, VPP Settlement, ¶¶ 18, 29.
[223] Hr. Ex. 131, VPP Settlement, ¶ 30.

express allocation of minimum VPP capacity to targeted, capacity-constrained distribution feeders.[224]

2. Discussion

190. Pursuant to Rule 1408(b) of the Rules of Practice and Procedure, 4 CCR 723-1, the Commission may approve, deny, or require modification to any settlement as the public interest requires. When reviewing a settlement, the Commission considers whether the terms adequately address the issues raised in the proceeding and reach a result that is just, reasonable, and in the public interest. As the proponents of an order approving the settlement, the settling parties bear the burden of proof to establish by a preponderance of the evidence that the settlement is just and reasonable and in the public interest.[225] In determining whether to approve a settlement, the Commission balances the longstanding policy of encouraging settlements in contested cases[226] and the Commission's independent duty to determine whether matters are in the public interest.[227] The Commission does not necessarily need to find the settled terms are the same as the Commission would have reached; rather, the Commission considers whether the settled terms adequately address the issues raised in the proceeding and reach a result that is just and reasonable and in the public interest.[228]

191. The Commission applies these principles and legal standards here to assess the VPP Settlement in light of the various objections that UCA, Mr. Althouse, and CEO raise. We discuss the relevant settlement provisions and testimony below and provide our findings and conclusions.

[224] Hr. Ex. 131, VPP Settlement, ¶ 30.
[225] § 24-4-105(7), C.R.S.; § 13-25-127(1), C.R.S.; Rule 1500, 4 CCR 723-1.
[226] *See*, *e.g.*, Rule 1408, 4 CCR 723-1.
[227] *See, e.g.,* Decision No. C12-1107 at p. 9 issued in Proceeding No. 11A-833E (September 24, 2012), citing *Caldwell v. Pub. Utils. Comm'n*, 692 P.2d 1085, 1089 (Colo. 1984).
[228] *See Caldwell*, 692 P.2d at 1089; *See also City of Boulder v. Colo. Pub. Utils. Comm'n*, 996 P.2d 1270, 1278 (Colo. 2000).

a. UCA's Challenges to the VPP Settlement

192. UCA opposes the lack of a competitive solicitation for the VPP Program's initial rollout in the VPP Settlement. UCA argues that a competitive solicitation (as opposed to the standard offer format) puts competitive pressure on aggregators to provide VPP capacity at the lowest cost in order to win bids. UCA acknowledges that a competitive solicitation creates uncertainties that might make it more difficult for aggregators to participate in an immature VPP program. UCA asserts, however, that if the market can do the same service at a lower price, that means the ratepayers are paying for a higher cost service.[229] UCA warns the VPP Settlement allows the Company to discontinue the VPP program after two years of operation, so if the Commission is interested in evaluating a competitive VPP solicitation it should do so now.[230]

193. Alternatively, if the Commission is unwilling to require competitive bidding for the entire VPP Program, UCA recommends the Commission order the Company to use competitive bidding for a portion of its VPP needs at the start of the program, rather than wait two years. In addition, UCA recommends that in the second-year evaluation advice letter, the Company be required to propose a more expansive use of competitive procurements, up to and including the total remaining capacity obligations of the VPP program. UCA asserts the Commission should not limit potential ratepayer savings by capping the amount of VPP capacity acquired via a competitive solicitation or limiting when such a solicitation should occur.[231]

194. Several parties oppose UCA's position that the VPP program must include an immediate competitive solicitation. For instance, SUN asserts that SB 24-218 requires the VPP program be implemented through a tariff with a performance-based compensation structure, as

[229] UCA SOP at p. 22.
[230] UCA SOP at pp. 22-23.
[231] Hr. Ex. 607, Villareal Settlement Testimony, p. 15.

opposed to a competitive solicitation.[232] SUN further argues that UCA failed to cite any other VPP program that uses a competitive solicitation for aggregations of customer-sited DERs to provide the services contemplated in the statute. SUN claims that UCA's position demonstrates a fundamental misunderstanding about how successful VPP programs operate around the country and fails to acknowledge substantial shortcomings of competitive solicitations for procuring VPPs.[233] In contrast, SUN asserts the standard offer tariff with performance-based compensation framework that the VPP Settlement proposes has a strong track record in attracting customers and delivering grid support capacity, including the Massachusetts Connected Solutions program and the California Demand Side Grid Support program.[234]

195. ACE similarly opposes the UCA's position, asserting aggregated DERs are fundamentally different from bulk power system resources procured through competitive solicitation. ACE asserts using a competitive solicitation to acquire VPPs is just as likely to chill participation as it is to yield lower prices.[235]

196. AEU asserts the requirement found in the VPP Settlement for Public Service to propose a 5 MW competitive solicitation after the first two years, addresses the issue of a competitive solicitation in a fair and balanced manner. According to AEU, not having a competitive solicitation until after the first two years is critical because it will provide time and opportunity to establish the program, iron out program details, and address unanticipated issues before adding a competitive solicitation, which will increase administrative complexity. AEU further argues this sequence will allow time to develop a structure for a competitive

[232] SUN SOP at pp. 5-6.
[233] SUN SOP at p. 6.
[234] SUN SOP at p. 7.
[235] ACE SOP at p. 29.

solicitation and asserts that no party has provided a detailed proposal for how such a competitive solicitation would operate.[236]

197. In its SOP, Staff does not directly address UCA's argument but endorses the VPP Settlement, without modification. Staff argues the VPP Settlement sets out a path to consider a competitive solicitation after the first two years which promotes long-term fairness and feasibility of the VPP program.[237]

b. Findings and Conclusions on UCA's Challenges

198. We generally agree with UCA that the VPP program ideally would utilize a competitive solicitation to help ensure VPPs are procured at the lowest possible price. The ultimate goal of the VPP program is to ensure the VPP compensation payments—which ratepayers fund—offset the need for additional capital spending associated with distribution, transmission, and generation. To achieve this long-term goal, the VPP program will likely need to evolve in several ways, including the ability to scale, penalties when VPPs fail to perform, and the procurement of VPP resources through a competitive solicitation.

199. While we agree with UCA's long-term vision of the VPP program, we reluctantly find that it would be premature to adopt UCA's proposals at this time. The VPP Settlement provides a reasonable pathway to create a market for aggregators and participants, including through its use of a standard offer tariff. Even if requiring a competitive solicitation for VPP resources at the outset resulted in a better price for VPP resources, it may not result in a better result. Using a standard offer tariff for the first two years of the VPP Program provides important certainty during the initial years of the program that will help kickstart broad participation.

[236] AEU SOP at p. 5.
[237] Staff SOP at pp. 30-31.

In addition, as AEU argues, the first two years of the VPP Program can be used to iron out program details and develop a structure for a competitive solicitation proposal—which is currently lacking. The Commission agrees with Staff that the VPP Settlement's pathway to consider a competitive solicitation after the first two years promotes long-term fairness and feasibility of the VPP Program.

c. Mr. Althouse's Challenges to the VPP Settlement

200. Mr. Althouse raises several challenges regarding the VPP Settlement. Mr. Althouse first argues that several value components of VPPs listed in SB 24-218 were not included in the performance-based compensation agreed upon in the VPP Settlement. Citing § 40-2-132.5(8)(b)(XI), C.R.S., Mr. Althouse asserts that SB 24-218 intends for the full DER value stack to be captured.[238] More specifically, Mr. Althouse notes the VPP Settlement allows Public Service to call VPP events with as little as one-hour notice and argues the value of time is not compensated. According to Mr. Althouse, the Company admitted that energy delivered in one hour has a higher value. To illustrate this concern, Mr. Althouse states that his favored DER will utilize his EV. While his EV can be charged and available with 24-hours' notice, he states he would not have free use of his car with only one hour's notice.[239]

201. In addition, Mr. Althouse argues that customers must have grid information showing the locational value of their property before negotiating with an aggregator.[240] He argues that simply leaving compensation to be worked out between the prosumers and aggregators is akin to throwing prosumers to the "aggregator wolves without any protections."[241]

[238] Mr. Althouse's SOP at pp. 4-5, 11.
[239] Mr. Althouse's SOP at p. 11.
[240] Mr. Althouse's SOP at p. 11.
[241] Mr. Althouse's SOP at p. 10.

202. Finally, Mr. Althouse asserts the VPP Settlement requires new emissions requirements beyond the existing emission permitting. Mr. Althouse opposes this concept and argues that Colorado farmers "should not be prevented from seeking biofuel grants to become Prosumers."[242] Mr. Althouse suggests such biofuel resources can help address intermittent renewables and even provide seasonal energy storage. He asserts that VPPs in the European Union have widely adopted biofuels to address periods where there is little wind or solar energy.

203. SUN argues the Commission should approve the VPP Settlement over Mr. Althouse's objections. According to SUN, the VPP Settlement is designed to deliver a peak load reduction capacity service and that the component resources of the participating VPPs will be operated in a manner to provide that service. This in turn means the compensation methodology in the VPP Settlement incorporates grid values directly applicable to this service. SUN asserts this compensation structure is an appropriate starting point for launching a VPP program and that the VPP Settlement provides a framework that enables the program to adapt and unlock additional values over time.[243]

d. Findings and Conclusions regarding Mr. Althouse's Challenges

204. We decline to adopt Mr. Althouse's recommendations at this time. Similar to UCA's position, we generally agree with Mr. Althouse's vision of a VPP program in which a broad array of DERs receive tailored compensation and in which prosumers have location-specific information about the value their DERs provide. Nevertheless, we reluctantly find the VPP Settlement is a reasonable approach that allows the VPP program to continue to evolve and improve over the next several years.

[242] Mr. Althouse's SOP at p. 12.
[243] SUN SOP at pp. 8-9.

205. As to his first challenge, Mr. Althouse is correct that SB 24-218 requires VPP compensation to “reflect the full value of services.”[244] On this point, Mr. Althouse argues the time value associated with providing energy with one-hour notice is not compensated. Mr. Althouse ignores, however, that the compensation methodology of the VPP Settlement is based in part on the expected cost of a utility-scale four-hour battery.[245] Such utility-scale batteries require far less than one-hour notice to be dispatched, yet they form the basis of the generation component of VPP compensation.

206. Throughout this Proceeding, parties have argued about the appropriate balance between holding VPP resources to the same standards as bulk-system resources and an appropriate compensation level. Acknowledging arguments that VPPs should not be held to the same performance standards as bulk-system resources, Public Service in Rebuttal argued it is thus reasonable that VPPs not receive the same level of compensation as bulk-system resources.[246] In sum, the compensation methodology set forth in the VPP Settlement does not ignore the time value of providing resources with one-hour notice. Rather, it strikes a reasonable balance between the compensation VPPs receive and their ability to meet the same performance standards as bulk-system resources.

207. More fundamentally, the underlying structure of the current aggregator DERMS relies on scheduled events that address periods of high load and coincident peaks on the bulk system. In this structure, it will be difficult to always have 24-hours’ notice prior to an event. However, as we move to a future that uses a grid DERMS system, the underlying structure will become much more dynamic and automated. Events will not necessarily track the bulk-system

[244] § 40-2-132.5(8)(b)(XI), C.R.S.
[245] *See* Hr. Ex. 122, Pollock Rebuttal, pp. 75-76; Hr. Ex. 131, VPP Settlement, ¶ 4.
[246] *See* Hr. Ex. 122, Pollock Rebuttal, pp. 61-66.

peaks, but may instead be coincident with peaks on the distribution system. This type of system will likely require a much more rapid response to signals than is currently contemplated in the VPP Settlement. We invite Public Service, in its next DSP, to opine on whether a new prosumer tariff will be necessary at that point. In other words, with the current aggregator DERMS technology, the current compensation methodology is appropriate for rewarding participation in set events that coincide with the bulk system peaks. Public Service should opine whether a new type of tariff would be better suited for a future grid DERMS system in which participation is more automated and dynamic.

208. Regarding Mr. Althouse's assertion that prosumers must have grid information showing the locational value of their property before negotiating with an aggregator, we note paragraph 22 of the VPP Settlement largely addresses this concern. Paragraph 22 states: "The Company will develop a process to make available to individual customers information as to whether they are on a feeder eligible for the distribution component of aggregator compensation."[247] Given the incipient nature of the VPP Program, this is a reasonable approach that will help ensure Mr. Althouse's concerns are addressed, especially given our other decisions making it easier for interested parties to access hosting capacity analysis and other distribution information without NDAs (see Section H, below).

[247] Hr. Ex. 131, VPP Settlement, ¶ 22.

209. Mr. Althouse's final objection regarding the treatment of biofuels is also already addressed in the VPP Settlement. Paragraph 24 states the following:

> The AVPP Program will not allow for enrollment of methane-based resources, whether fueled by fossil gas or non-fossil gas, or hydrogen-based resources at this time. The Company agrees to work with prospective aggregators or providers of methane- or hydrogen-fueled resources and interested stakeholders to identify a system to certify and track environmental attributes of these resources. After an appropriate verification and tracking system is identified, the Company may propose to include in the AVPP Program methane- and hydrogen-fueled resources which utilize the identified verification and tracking system.[248]

210. This VPP Settlement provision is a reasonable approach to treating methane (including biofuels) and hydrogen resources. One of the VPP services that § 40-2-132.5(8)(b)(XI), C.R.S. enumerates is "clean peak service." It is difficult to understand, however, whether a biofuel resource offers clean peak service until after a verification and tracking system is identified. It would be inappropriate to attempt to structure a fair compensation level for methane and hydrogen resources until the full emissions impacts of such resources are better understood.

e. CEO's Request

211. Initially in its Direct Testimony, Public Service proposed including VPP performance within the Company's demand management performance incentive mechanism ("PIM"), citing concerns the VPP program could reduce participation in existing demand management programs. In response to concerns from WRA and Staff, however, the Company changed course in Rebuttal. In Rebuttal, Public Service agrees with Staff and WRA that inclusion of the VPP program capacity in the calculation of the demand management PIM can be assessed

[248] Hr. Ex. 131, VPP Settlement, ¶ 24.

in future proceedings, including the DSM strategic issues proceeding (anticipated in July 2026).[249] Nevertheless, Public Service reiterates its concern that the VPP program may encourage customers to move out of existing demand management programs. Thus, while Public Service no longer seeks to modify the demand management PIM in this Proceeding, the Company asks that VPP capacity savings be counted towards meeting future demand management goals to avoid the potential for unintended consequences.[250]

212. In its SOP, CEO recommends the Commission prohibit Public Service from including VPP achievements in the Company's calculation of its existing demand management PIM. CEO adds that any adjustments to the demand management PIM should occur in the next DSM strategic issues proceeding, and not in this DSP.[251]

213. WRA and Staff do not appear to address this issue in their SOPs, but both intervenors joined the VPP Settlement, which adopts the Company's Rebuttal position.

f. Findings and Conclusions regarding CEO's Request

214. We deny CEO's request regarding the demand management PIM to the extent it is inconsistent with the Company's Rebuttal position and the VPP Settlement.[252] Public Service raises legitimate concerns that customers currently enrolled in demand management programs could switch to a VPP instead. To avoid the potential for unintended consequences, VPP capacity savings should be counted towards meeting future demand management goals. In any event, the inclusion of the VPP program capacity in the calculation of the demand management PIM can be

[249] Hr. Ex. 128, Austin Rebuttal, pp. 31-32.
[250] Hr. Ex. 128, Austin Rebuttal, p. 32.
[251] CEO SOP at pp. 37-38; Hr. Ex. 402, Durkay Cross Answer, p. 9.
[252] The VPP Settlement does not expressly address the demand management PIM. However, this issue is addressed in the Company's Direct and Rebuttal and the VPP Settlement adopts the Company's VPP Program "as presented in its Direct Testimony, modified in its Rebuttal Testimony, and as further modified by this AVPP Settlement." (Hr. Ex. 131, VPP Settlement, ¶ 1).

assessed in future proceedings, consistent with the Company's Rebuttal position and the VPP Settlement.

215. In the future proceedings in which the Commission and parties assess including VPP program capacity in demand management goals—including as it relates to the demand management PIM—it will be critical to establish a consistent and transparent data tracking protocol. Interested stakeholders and the Commission must have the ability to compare performance data of both VPP resources and demand management resources so that we can understand the performance data from year to year and from program to program.

g. Approval of the VPP Settlement

216. Having addressed the above challenges to the VPP Settlement, the remaining portions are unopposed.[253] We find that the VPP Settlement sets forth a reasonable approach for launching Colorado's first VPP Program, is supported by a broad range of stakeholders, and is in the public interest. While we ultimately approve the VPP Settlement without modification, we do so in the context of our discussion above. For instance, consistent with UCA's long-term vision of the VPP program, the ultimate goal is to have the VPP program offset the need for additional capital investment in distribution, transmission, and generation in such a way that the VPP compensation payments put downward pressure on rates. We see the VPP program evolving over the coming years in several ways, including adopting competitive solicitations and more stringent performance requirements to ensure that VPP resources cost effectively offset bulk-system investments at the lowest cost to ratepayers. To Mr. Althouse's points, as the VPP program evolves we expect it to be able to incorporate a growing array of DERs with more tailored compensation

[253] We address the issue of the AVPP feeders list below in Section H.

methodologies. Indeed, the switch to a grid DERMS structure would likely require a new paradigm for certain classes of DERs.

217. While the VPP program we approve in this Decision is not the VPP program we expect to have in the coming years, we find that the VPP Settlement will spur robust participation from aggregators and prosumers. At the same time, the VPP Settlement creates pathways for the continued development of the VPP program by establishing stakeholder processes, reporting, and the requirement for Public Service to file an evaluation advice letter after the VPP program has operated for two years. We thus find the VPP Settlement to be just, reasonable, and in the public interest.

F. Grid Modernization Adjustment Clause Eligible Distribution Activities

a. Company's Direct Case

218. As contemplated by SB 24-218, the Company proposed a GMAC rider in this case, which it proposed to be effective January 1, 2026. In its direct case, the proposed DSP investment was projected to result in a GMAC revenue requirement of $291 million by 2028, and $406 million by 2029.[254] The Company also offered illustrative rates and bill impacts of the proposed GMAC rider; under the proposed GMAC, residential customers would see a bill increase of $8.71, or 9 percent, by 2029.[255] [256]

219. For all categories of costs, the GMAC would include a return component, calculated by applying the Company's most recently approved weighted average cost of capital ("WACC") to the projected retail jurisdictional portion of the 13-month average of the relevant

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[254] Hr. Ex. 107, Peuquet Direct, p. 31 (Table JJP-D-2).

[255] Hr. Ex. 107, Peuquet Direct, p. 39 (Table JJP-D-3) and p. 41 (Table JJP-D-4).

[256] In the Company's Rebuttal case, the Company affirmed that it is seeking recovery of investments through the GMAC only for 2026, 2027, and 2028 in this Proceeding; under these periods, the cumulative residential bill impact would be 6.4 percent. Hr. Tr. August 25, 2025, pp. 171-172.

net plant balance. It would also include associated "plant-related ownership costs," including depreciation expense, income tax expense, and accumulated deferred income taxes. For certain categories of costs, the GMAC would also include projected operations & maintenance ("O&M") expenses.[257]

220. The Company proposed four categories of costs to be included in the GMAC:

a) "**2024 and 2025 distribution activities**," which are currently being recovered in the Transmission Cost Adjustment ("TCA"), specifically in the TCA-Distribution ("TCA-D") rate component established by SB 24-218. The Company also proposed that true-ups for the 2024 and 2025 TCA-D would be included in the projected 2026 and 2027 GMAC rates, allowing for the TCA-D to expire. The Company argues that this would be consistent with Commission decision C24-0720.[258]

b) "**Equipment to Advance Distribution Activities**" ("EADA"), a specific subset of equipment specifically contemplated for recovery under SB 24-218 which is currently being recovered through the TCA-D.[259]

c) "**Type 1 distribution activities**," the categorization used by the Company for activities that affordably and strategically benefit or advance state policy goals, including "greenhouse gas emissions reductions, BE, increased reliability, and increased resiliency." Under the Company's proposal, Type 1 distribution activities would be included in the GMAC in their entirety. The Company proposed the following types of costs to be considered Type 1 activities:

    i. capacity projects;

    ii. asset health and reliability projects;

    iii. informational and operational technology investments, and certain AGIS investments;

    iv. undergrounding projects;

    v. EADA;

    vi. WMP projects, to the extent they were not recovered outside of the GMAC; and

[257] Hr. Ex. 107, Peuquet Direct, p. 26.

[258] Hr. Ex. 107, Peuquet Direct, pp. 17-18. In Proceeding No. 24M-0317EG, the Commission addressed the proper implementation of SB 24-218 regarding Public Service's then-upcoming advice letter filing to enable it to recover the costs of the investments to be placed in service and the expenses incurred for certain distribution activities through December 31, 2025, as required in § 40-2-132.5(4)(d), C.R.S.

[259] Hr. Ex. 107, Peuquet Direct, p. 15.

vii. Incremental O&M projects of "a little over $6 million per year",[260] related to incremental staffing needs and community outreach.[261]

d) "**Type 2 distribution activities**," the categorization used by the Company for other distribution activities undertaken as part of the DSP. Under the Company's proposal, Type 2 distribution activities would be included in the GMAC subject to performance-based framework. As described by the Company, examples of Type 2 activities would include:

i. Extensions for new service if those extensions do not serve policy goals;

ii. relocation of distribution infrastructure that would not result in increased capacity, reliability, or resilience;

iii. streetlighting investments; and

iv. investments in fleets and tools that are not necessary to support increased capacity, reliability, or resilience. [262]

221. The Company tied Type 2 distribution activities back to SB 24-218, which contemplates that, for "distribution activities … that the Commission finds do not benefit or advance the goals," recovery may occur through the GMAC if the utility meets criteria established in Commission-approved performance-based framework.[263] Under SB 24-218, the performance-based framework must include:

a. Applicable interconnection timelines;

b. applicable energization timelines, so long as the energization timelines are not applicable in the first DSP filed after the effective date of SB 24-218; and

c. reasonable and cost-effective targets measured in megawatts for flexible load and demand management, with a general target-setting framework evaluated in the first DSP filed after the effective date of SB 24-218 and further developed through other planning processes, and applicable in the second DSP filed after the effective of SB 24-218 and subsequent DSPs.[264]

222. The Company proposed that, in any given year, the revenue requirement would be calculated for the total pool of Type 2 distribution activities; then, the percentage of that total

[260] Hr. Ex. 101, Ihle Direct, p. 12.
[261] Hr. Ex. 101, Ihle Direct, pp. 64-66.
[262] Hr. Ex. 101, Ihle Direct, p. 66.
[263] § 40-2-132.5(7)(b)(III), C.R.S.
[264] § 40-2-132.5(5)(e), C.R.S.

revenue requirement that would be included in that year's GMAC would be calculated based on the Company's performance on applicable performance screens over that same year. For instance, under the Company's proposal, if in year 2 of the GMAC the Company is not able to meet all applicable performance screens, then the revenue requirement would be discounted for that year even for projects that went into service in year 1. But in year 3 of the GMAC, if the company *does* meet all performance screens, then the full revenue requirement would be recovered for projects that went into service in years 1, 2, and 3.

223. Because the Company's performance in any given year cannot be known in advance, the Company proposed to include all Type 2 distribution activities at 100 percent value in the November 1 Advice Letter filing and projected rate, and then include any adjustments for underachievement in the April 1 true-up filing.[265] The Company also proposed that, if Type 2 distribution activities ultimately end up meeting requirements for Type 1, that it may propose adjustments through true-up reports or future DSPs to reflect that.[266]

224. For this DSP, the Company's proposed performance-based framework is solely based on interconnection timelines, the one performance screen required by SB 24-218 to be used in the first DSP after its implementation. Specifically, the Company proposed to use the existing timing requirements for the interconnection of DERs, as established in the Commission's Interconnection Procedures and Standards. Under this proposal, if the average number of DER interconnection days late is zero, the Company would be authorized recovery of 100 percent of its Type 2 distribution activities; this percentage of cost recovery would decrease on a sliding scale

[265] Hr. Ex. 107, Peuquet Direct, pp. 26-29.
[266] Hr. Ex. 101, Ihle Direct, p. 71.

until 60 average days late, at which point the recovery of Type 2 distribution activities would be 0 percent.[267]

225. The Company also requested that AVPP administration costs be recovered through the GMAC. Administration costs would include costs to set up and operate the AVPP program, including costs related to integrating aggregators into the aggregator DERMS, program management costs, information technology costs, and educational materials. Administration costs would be net of any service fee revenue recovered from aggregators through a service fee. Public Service states that the recovery of AVPP administration costs through the GMAC would be consistent with SB 24-218.[268]

b. Answer Testimony

226. Staff proposes an annual $25 million GMAC revenue requirement cap, beyond which, under Staff's interpretation, spending would not "affordably" advance statutory goals.

227. Staff expresses concern about the impact of the Company's proposed GMAC on affordability and customer rates. Staff calls attention to the projected 9 percent residential bill increase by 2029, noting that this increase would be on top of the bill increase that has already occurred due to the implementation of the TCA-D, and that this increase does not reflect additional bill increases from other proceedings, such as the Clean Energy Plan[269], WMP, JTS Proceeding, or metro Denver transmission CPCN proceedings.[270] Although the Company has talked about managing bill increases through load growth in this and other proceedings, Staff points out that

[267] Hr. Ex. 101, Ihle Direct, pp. 73:16-75:6.
[268] Hr. Ex. 116, Ihle VPP Direct, p. 27-28. § 40-2-132.5(8)(f), C.R.S. "A qualifying retail utility shall recover costs to facilitate a Virtual Power Plant program, including foundational technology costs or investments, [O&M] expenses, operating technology costs or investments, and information technology costs or investments, through the [GMAC]."
[269] Proceeding No. 21A-0141E.
[270] Proceeding No. 24A-0560E.

future sales growth is inherently uncertain, and that much of the sales growth forecasted by the Company is that of large customers who take transmission level service and do not pay for distribution costs, and as such, growth in that transmission level customers would do little to reduce GMAC bill impacts.[271] Staff calculates its $25 million revenue requirement as approximately a 0.76 percent retail rate impact, when calculated as a percentage of total revenues excluding transmission customers, and using a "10 percent" estimate of the relationship between revenue requirement and capital expenditure, states that its $25 million cap would be roughly aligned with $250 million of capital investment going through the GMAC. Staff also notes that its 0.76 percent retail rate impact is within the range established SB 24-218 for the TCA-D, which it posits could be seen as a guidepost for the GMAC as well. [272]

228. Staff emphasizes the "affordably and strategically" language in SB 24-218, noting that neither "affordably" nor "strategically" is defined in SB 24-218, thus leaving discretion to the Commission. Accordingly, Staff recommends the Commission minimize GMAC recovery "to the greatest extent that the law allows," by limiting recovery to only Type 1 activities based on affirmative findings that the activities affordably and strategically benefit or advance state goals.[273] Staff further points out that the Commission, at all times, has the duty to ensure that rates are just and reasonable, and that duty underpins all Commission regulatory activity and is not modified by the enactment of the DSP statute.[274]

229. Staff opposes the Company's plan to roll the TCA-D revenue requirement into the GMAC. Staff recommends that the distribution activities currently recovered through the TCA-D

[271] Hr. Ex. 500, Haglund Answer, pp. 27-28.
[272] Hr. Ex. 500, Haglund Answer, pp. 29-31, discussing the retail rate impact cap established for 2024 and 2025in § 40-2-132.5(4)(b), C.R.S.
[273] Hr. Ex. 500, Haglund Answer, pp. 18-21.
[274] Staff SOP at pp. 6-7.

be kept separated from the GMAC revenue requirement, particularly in the context of Staff's $25 million GMAC revenue requirement cap.[275]

230. Staff additionally opposes the Company's plan to roll EADA into the GMAC, and asserts that the only EADA that should be recoverable is the $52 million currently recovered through the TCA-D (subject to prudence review). Staff also proposes that the Commission order the Company to draw down its EADA inventory over the period covered in this DSP. Staff understands SB 24-218 to limit EADA to expenses incurred prior to December 31, 2025, which is projected to be $52 million. Staff further asserts that the requirement to allow recovery of EADA does not apply beginning January 1, 2026, when the GMAC goes into effect, and that EADA is not inherently "used and useful."[276]

231. Staff recommends that incremental labor costs not be included in the GMAC, and instead be presented in a general rate review for recovery through base rates. Staff argues that while SB24-218 explicitly requires a staffing analysis within the DSP, the requirement does not direct recovery of those costs to occur within the GMAC; in that context, Staff recommends that the "affordably and strategically" language of SB 24-218 justifies excluding labor costs from recovery through the GMAC.[277] Staff argues that the absence of current or historical labor costs diminishes the understanding of total staffing needs, and contrasts this with a rate case where labor can be viewed more holistically; Staff additionally argues that dollar-for-dollar recovery would provide little incentive for Public Service to be efficient or seek cost-effective staffing.[278]

[275] Hr. Ex. 500, Haglund Answer, pp. 32-33.
[276] Hr. Ex. 500, Haglund Answer, pp. 48-51.
[277] Hr. Ex. 504C, Ghebregziabher Answer, pp. 12-15.
[278] Hr. Ex. 504C, Ghebregziabher Answer, pp. 15-21.

232. As an alternative labor recommendation, Staff recommends additional transparency on labor costs in annual DSP reporting as well as when those costs are ultimately rolled into base rates, including information on current as well as future staffing levels as well as continued reporting on capital and O&M expense splits. Staff also recommends limitations on recovery of those costs consistent with those limitations approved in the Company's most recent rate case, such as restrictions on Annual Incentive Plans and Long-Term Incentive.[279]

233. Staff does agree with the Company that SB 24-218 requires AVPP administrative costs be recovered through the GMAC and suggests the Commission allows the Company to do so.[280]

234. UCA recommends that the Commission "tie any GMAC to the rate case, rather than the DSP." UCA highlights the inherent uncertainty in the DSP, notes that most DSPs across the country are "informational," and asserts that the Commission needs to make an explicit decision as to whether the DSP will be more than an informational filing. UCA asserts that the existing DSP rules would need to be amended to recognize that the DSP could also be a "ratesetting-type proceeding," rather than just a planning proceeding, to ensure that stakeholders and parties are ready to address cost recovery issues. UCA also notes that a rate case is the sole adjudicatory process where all utility costs can be compared.[281]

235. CEO agrees with Staff that the Commission has large discretion on whether to approve cost recovery through the GMAC, highlighting the "affordably and reliably" language used throughout SB 24-218. CEO recommends rejecting the Company's Type 1 and Type 2 framework and instead adhering directly to the criteria laid out in the DSP statute. Under CEO's

[279] Hr. Ex. 504C, Ghebregziabher Answer, pp. 5-6.
[280] Hr. Ex. 500, Haglund Answer, pp. 21-22; p. 61.
[281] Hr. Ex. 601, Villarreal Answer, pp. 33-38.

proposed framework, most of the Company's proposed "Type 1 distribution activities" would still qualify for GMAC cost recovery; however, CEO states that other activities should only be recovered through the GMAC if applicable performance screens are approved by the Commission in a DSP proceeding. CEO witness Durkay offers Figure JPD-1, which reflects some differentiation between the Company's proposed Type 1/Type 2 framework and CEO's suggested cost recovery designation.[282] Accordingly, as the only performance screen required by SB 24-218 to be used in this DSP and the only performance screen proposed by the Company is the interconnection framework, CEO asserts that only activities which actively contribute to interconnection timelines would be appropriate to include for Type 2 recovery,[283] and that the Commission should not approve GMAC eligibility for any projects which would need to qualify for the GMAC via energization or load management frameworks.[284]

236. In Cross-Answer testimony, CEO further asserts that the interconnection framework should be more stringent than that proposed by the Company, recommending that Type 2 GMAC recovery should be based on how many days *early* an interconnection is compared to the Commission's rules, and that the Company should be ineligible to recover costs through the GMAC for distribution activities that result in the average interconnection length exactly meeting or exceeding what is already required.[285]

237. SWEEP/NRDC "generally support" the Company's proposed Type 1 and Type 2 framework, but are concerned about the expansive view the Company takes of what is considered a Type 1 investment, particularly the inclusion of all resiliency investments as Type 1 and the bill

[282] Hr. Ex. 400, Durkay Answer, p. 24.
[283] Hr. Ex. 400, Durkay Answer, pp. 21-24.
[284] Hr. Ex. 400, Durkay Answer, pp. 18-19.
[285] Hr. Ex. 402, Durkay Cross-Answer, pp. 5-7.

impacts of this classification. Regarding Type 2 investments, SWEEP/NRDC assert that the Company should need to *exceed* minimum Commission requirements, rather than meet them, to fully recover Type 2 investments through the GMAC. Specifically, while acknowledging that they are not experts on Colorado's interconnection policy, SWEEP/NRDC suggest that simply meeting the interconnection timelines required by Commission rules should result in no more than 50 percent of Type 2 activities receiving GMAC recovery.[286]

238. Like SWEEP/NRDC, WRA also expresses concern about the amount of the Company's DSP budget proposed to be "Type 1," which it calculates to be 81 percent of the total GMAC-eligible budget. WRA specifically recommends that Asset Health and Reliability investments should be classified as Type 2 activities rather than Type 1, asserting that the Company has not sufficiently demonstrated that those investments are strategic and affordable.[287] WRA observes the sizable increase in the Asset Health and Reliability budget from past years, and particularly the emergence of the targeted undergrounding budget; expresses concern that the Company's discussion of its Asset Health and Reliability investments in testimony is "relatively general;" and notes that the Company does not estimate the expected improvement in reliability investments resulting from its proposed portfolio. [288]

239. WRA also recommends modifications to the Company's proposed performance-based framework to address reliability. WRA views the performance screens required by the statute as a *minimum* and asserts that the Commission has authority to add other components, and states that reliability is fundamental in determining the performance of the distribution system. WRA notes that several quantitative metrics already exist and are tracked

[286] Hr. Ex. 1400, Alatorre Answer, pp. 24-25.
[287] Hr. Ex. 1700C, Valentine Answer, pp. 51-54.
[288] Hr. Ex. 1700C, Valentine Answer, pp. 44-48.

through the Company's QSP that could be used to judge reliability performance, including SAIDI, SAIFI, CAIDI, and SAIDI by Census Block Group ("CBG-SAIDI"), which WRA asserts has been used as a performance metric in past cases.[289] WRA additionally notes that the Company's proposed interconnection screen would more than likely result in full GMAC recovery for Type 2 costs, given that the Company processed interconnection applications much quicker than required under Commission rules in 2024, averaging 12 days for Level 1 applicants compared to an allowed timeline of 50 days.[290]

c. Rebuttal

240. Public Service continues to support its GMAC proposal in its Rebuttal Testimony, framing the GMAC as a crucial component of SB 24-218 and proactive distribution planning in the state of Colorado; the Company does not propose any alterations to its classification of "Type 1" or "Type 2" activities, and continues to advocate for its proposed performance screens.

241. Company witness Robert Kenney presents the Commission as having two choices – embracing the directives of SB 24-218 by approving the Company's DSP and GMAC recovery, or foreclosing economic growth, customer opportunities and policy progress. Kenney describes the language in SB 24-218 surrounding cost recovery as "specific, unambiguous, and affirmative," and criticizes intervenors for "ignor[ing] this directive" and being out of step with the legislation and state policy in general.[291] Company witness Jack Ihle characterizes SB 24-218 as a "two-way street," with investment levels as well as cost recovery through the GMAC; several intervenors,

[289] Hr. Ex. 1700C, Valentine Answer, pp. 56-60.
[290] Hr. Ex. 1700C, Valentine Answer, p. 54; Att. CV-17; Att. CV-18.
[291] Hr. Ex. 120, Kenney Rebuttal, pp. 8-10.

he asserts, would rather have the DSP be a "one-way street," *with* the investment but *without* (or with very limited) GMAC recovery.[292]

242. The Company characterizes Staff's proposed $25 million revenue requirement cap as "onerous" and as "extensive, unworkable, and [contrary to] SB 24-218." The Company notes that SB 24-218 does not contemplate a cap on the GMAC, but *does* contain a cap on the TCA-D as well as EADA investment; the Company extrapolates from this that the Legislature would have created a cap for the GMAC as well if that was its intention. The Company asserts that Staff's proposal would discourage investments, disregards proactive planning analyses done as part of the DSP, and shows Staff's aversion to concurrent recovery. The Company also believes that Staff takes an overly narrow view of "affordability," looking at near-term rate impact while ignoring considerations like inflationary pressures of deferring investments and economic development.[293]

243. Public Service additionally notes that Staff witness Haglund only makes one reference to Type 2 activities in his Answer Testimony, and that Staff's proposal does not seem to provide for any recovery for Type 2 activities in the GMAC,[294] which, the Company says, goes to show that Staff's proposal does not give weight to the language of the statute or the structure established in SB 24-218.[295]

244. Public Service disagrees with Staff's proposal to keep the TCA-D revenue requirement separate from the GMAC. The Company points to Decision No. C24-0720 in Proceeding No. 24M-0317EG, which states that "the true-up for 2025 expenditures [on distribution

[292] Hr. Ex. 121, Ihle Rebuttal, p. 19.

[293] Hr. Ex. 121, Ihle Rebuttal, pp. 37-43.

[294] In Answer Testimony, Staff recommends "limiting GMAC recovery to *only* those distribution activities that it determines to be Type 1 activities," effectively confirming Public Service's interpretation; Hr. Ex. 500, Haglund Answer, p. 18:6-8.

[295] Hr. Ex. 121, Ihle Rebuttal, pp. 54-55.

activities] should be addressed as a feature of the GMAC."[296] Public Service also asserts that it is logical for all distribution costs associated with SB 24-218 to be in the same line item, and that in the longer-term inclusion of distribution costs in the TCA could lead customers to thinking that they are paying more for transmission costs. The Company also notes that, since there is a cap on the TCA-D, the Company will calculate separate revenue requirements for the TCA-D and GMAC, so even if a GMAC cap were approved the caps could be analyzed separately.[297]

245. The Company also continues to support the inclusion of EADA in the GMAC without a $52 million cap. Public Service asserts that Staff's proposal conflicts with both a plain reading of SB 24-218 ("a qualifying retail utility may spend or recover through the [TCA] or another existing adjustment clause, the revenue requirement associated with up to [$150 million] in investment to order [EADA equipment]") as well as the objectives of SB 24-218. Public Service also states that challenges related to EADA "are industry-wide" and there is no indication these challenges will cease after December 2025. The Company points out that Staff has not indicated that it is imprudent or unnecessary to invest in EADA.[298]

246. Regarding labor costs, Public Service states that personnel are an essential part of achieving the goals of distribution system planning, and describes the staffing analysis as a bottom-up analysis in which each team was engaged to understand challenges to implement DSP projects.[299] Public Service further asserts that all costs that are necessary to implement the DSP should be included in the same cost recovery mechanism in order to allow for a complete review, and notes that the labor costs proposed in this filing are incremental and unique to the DSP.

[296] Hr. Ex. 126, Peuquet Rebuttal, p. 11; Decision No. C24-0720 at ¶ 28.
[297] Hr. Ex. 126, Peuquet Rebuttal, pp. 17-18.
[298] Hr. Ex. 121, Ihle Rebuttal, pp. 47-48.
[299] Hr. Ex. 121, Ihle Rebuttal, pp. 66:17-68:19.

Public Service also emphasizes that labor costs in the GMAC would be trued up to actuals, like other costs in the GMAC, and that the Company's TEP Rider also has labor costs.[300]

247. The Company also opposes UCA's GMAC recommendation, describing it as preserving the status quo. The Company asserts that UCA's proposal to tie the GMAC to a rate case is directly contradictory to SB 24-218, which states that a "qualifying retail utility shall recover … projected distribution activities through a [GMAC] established as part of a qualifying retail utility's first [DSP] application after the effective date." Similarly, the Company asserts that SB 24-218 *made* the DSP a ratemaking proceeding, by creating the GMAC and tying it to the DSP. The Company also describes UCA's proposal as preserving regulatory lag, and claims that jurisdictions in which GMAC-like mechanisms are only used as trackers or balancing accounts also accompany those mechanisms with future test years or multi-year rate plans, which are not applicable to Public Service at this time.[301]

248. The Company additionally notes that UCA witness Villarreal has an alternative recommendation which states that "the Commission may want to create performance obligations on projects proposed in a DSP."[302] Public Service says that this proposal of UCA is directly in line with the performance screens established within SB 24-218, and as such, "the Company has proposed exactly what Mr. Villarreal's alternative recommendation suggests."[303]

249. With regards to CEO's recommendation, Public Service expresses some confusion with how the two categories described by CEO differ from the Company's proposal, asserting that the "Type 1" and "Type 2" framework proposed was designed to align with the framework

[300] Hr. Ex. 126, Peuquet Rebuttal, pp. 18:8-21:5.
[301] Hr. Ex. 121, Ihle Rebuttal, pp. 48-52.
[302] Hr. Ex. 121, Ihle Rebuttal, p. 55, discussing Hr. Ex. 601, Villareal Answer, p. 31.
[303] Hr. Ex. 121, Ihle Rebuttal, pp. 55-56.

established in SB 24-218, and noting that the costs included in the CEO categories generally align with the "Type 1" and "Type 2" categorization of costs.[304]. Overall, the Company points out four areas of disagreement with CEO's position. First, CEO proposes to reclassify targeted undergrounding and Community Directed Undergrounding ineligible for GMAC recovery unless directly increases reliability or resiliency. The Company opposes putting "unnecessary hurdle[s]" on undergrounding and that different set of standards for undergrounding will discourage that work in places where it is appropriate based on engineering and implementation assessments."[305] Second, the Company characterizes CEO's proposed application of the performance screen for Type 2 Distribution Activities as "challenging to follow" but overly limiting." The Company opposes limiting Type 2 Distribution Activities to only those activities directly associated with interconnection are eligible for recovery based on performance under the proposed performance screen because it argues that its contrary to SB 24-218 and would be too difficult to determine the interrelationship between particular projects and purposes.[306] Regarding performance screens, Public Service disagrees with CEO that starting from the nature of the investment and matching it up with the nature of the screens is consistent with SB 24-218. Rather, the Company believes that the statute requires recovery of a wide group of distribution activities, and then establishes the performance screens to determine the proportion of recovery of those activities. Third, CEO proposes requiring a showing that a project or investment "directly increases reliability or resilience" for GMAC eligibility. Public Service expresses concerns that a showing of that activities directly increasing reliability or resilience is unclear, with many projects providing multiple value streams, and that a requirement of such a showing would invite litigation into the

[304] Hr. Ex. 121, Ihle Rebuttal, pp. 57-58.
[305] Hr. Ex. 121, Ihle Rebuttal, pp. 55-60.
[306] Hr. Ex. 121, Ihle Rebuttal, p. 61.

November 1 advice letter filings, while the April 1 true-up filing already provides an opportunity for reviewing activities and inquiry.[307] Finally, the Company opposes certain limitations on project eligibility for GMAC recovery that it construes as "overly narrow." The Company opposes CEO's suggestion that projects not directly approved in a DSP cannot be included in a November Advice Letter filing.[308]

250. Public Service disagrees with Sweep/NRDC's proposal to require exceeding Commission required interconnection timelines for full GMAC recovery of Type 2 activities. The Company asserts that a heightened standard is "not warranted nor contemplated by SB 24-218."[309]

251. Public Service disagrees with WRA's proposal to move Asset Health and Reliability from the Type 1 category to the Type 2 category, stating that investments interrelate with one another, and Asset Health and Reliability investments support Capacity investments, driving progress in policy goals. The Company additionally disagrees with WRA's proposal to further develop performance-based framework for Type 2 activities. Public Service states that SB 24-218 doesn't contemplate a "reliability component" in establishing the performance-based framework, and that including such a component would add significant complexity to the performance screen; The Company also notes that the Company has numerous PIMs already in place.[310]

[307] Hr. Ex. 121, Ihle Rebuttal, pp. 60-63.
[308] Hr. Ex. 121, Ihle Rebuttal, pp. 62-64.
[309] Hr. Ex. 121, Ihle Rebuttal, p. 64.
[310] Hr. Ex. 121, Ihle Rebuttal, pp. 65-66.

d. Stipulation

252. On August 15, 2025, a stipulation related to the GMAC (the "GMAC Stipulation") was filed in this Proceeding.[311] Public Service, Boulder, the Eastern Metro Area Business Coalition, ACE, SWEEP/NRDC, and AEU each joined the GMAC Stipulation. These six parties generally agree that proactive planning and investment in the distribution system is consistent with Senate Bill 24-218, agree to support the GMAC for eligible costs without caps on concurrent recovery, and support the Company's proposed GMAC budgets for 2026, 2027, and 2028. The signatories retain their rights with respect to other GMAC issues not addressed in the stipulation.[312]

e. Findings and Conclusions

(1) Overall Framework

253. Pursuant to § 40-2-132.5(7)(a), C.R.S., a utility shall recover, on an annual basis, projected distribution activities[313] through a grid modernization adjustment clause established as part of the qualifying retail utility's first distribution system plan application after May 22, 2024. Pursuant to § 40-2-132.5(7)(b)(I), C.R.S., a utility shall propose, and the Commission shall evaluate, "whether the projected distribution activities and corresponding budgets strategically benefit or advance the applicable targets, standards, plans, and regulations described in subsection

[311] GMAC Stipulation, filed as Hr. Ex. 133.

[312] GMAC Stipulation, ¶ ¶ 1-4.

[313] "Distribution activities" means: (I) Capital investment and operations and maintenance expenses associated with equipment upgrades, repair and replacement programs, conductor replacements, conductor installations, pole repair and replacement, overhead rebuilds, inspection, modeling, asset data gathering, defect corrections, and major line rebuilds; and (II) Similar activities and investments, including information and operational technology investments, with the objective of enhancing the distribution system to meet state decarbonization goals and federal, state, regional, and local air quality and decarbonization targets, standards, plans, and regulations. § 40-2-132.5(2)(h), C.R.S.

(5)(a) of § 40-2-132.5, C.R.S., or state energy policy goals, including greenhouse gas emission reductions, BE, increased reliability, and increased resiliency."

254. If the Commission finds that the projected distribution activities and corresponding budgets affordably and strategically benefit or advance the goals described in subsection (7)(b)(I) of § 40-2-132.5, C.R.S., the distribution activities are qualifying distribution activity recovery and recovery must occur through the grid modernization adjustment clause in a manner consistent with this section. However, for projected distribution activities and corresponding budgets that the Commission finds do not benefit or advance the goals described in subsection (7)(b)(I) of § 40-2-132.5, C.R.S., recovery may still occur through the grid modernization adjustment clause if the qualifying retail utility meets the criteria established in the performance-based framework approved by the Commission pursuant to subsection (5)(e) through the distribution system planning process.

255. The goals described in subsection (7)(b)(I) of § 40-2-132.5, C.R.S. include those described in subsection 5(a): (I) Federal, state, regional, and local air quality and decarbonization targets, standards, plans, and regulations; (II) The transportation, affordable housing, new infill housing, and building electrification policies of state and local law []; (III) State agency, local agency, and local government plans and requirements related to housing, economic development, critical facilities, transportation, and building electrification; (IV) Enforceable and funded federal, state, regional, and local policies, plans, goals, incentives, or requirements designed to increase access to distributed energy resources, electrified transportation, and building electrification in disproportionately impacted communities; and (V) The qualifying retail utility's approved renewable energy standard plan, clean heat plan, beneficial electrification plan, demand-side management plan, gas infrastructure plan, and transportation electrification plan.

§ 40-2-132.5(5)(a), C.R.S., as well as "state energy policy goals, including greenhouse gas emission reductions, [BE], increased reliability, and increased resiliency."

256. As a threshold matter, we reject UCA's proposal to delay establishment of a GMAC until a future rate case. Pursuant to § 40-2-132.5(7)(a), C.R.S., a utility shall recover "projected distribution activities through a grid modernization adjustment clause **established as part of the qualifying retail utility's first distribution system plan** application after May 22, 2024." (emphasis added). We find that establishing the GMAC rider in this Proceeding is consistent with a plain reading of § 40-2-132.5(7)(a), C.R.S., and also supported by the record in this Proceeding.

257. The Company puts forth a framework for analysis of GMAC eligible spending that largely reflects the statutory framework established in SB 24-218. While the Commission need not necessarily use the "Type 1/ Type 2" descriptors, we agree with the Company that § 40-2-132.5(7), C.R.S. sets forth two pathways to GMAC eligibility. The Company utilizes label "Type 1" to refer to the proposed distribution activities that it purports "affordably and strategically benefit or advance" the statutory goals. We agree with the Company that, for all projected distribution activities and corresponding budgets which the Commission finds "affordably and strategically benefit or advance" the statutory goals, recovery "must occur" through the GMAC consistent with § 40-2-132.5(7)(b)(II), C.R.S. The Company utilizes the label "Type 2" to refer to those proposed activities which it does not suggest "affordably and strategically benefit or advance" the statutory goals. The Company states that its Type 2 vernacular refers to "all other distribution activities undertaken as part of a Commission-approved Distribution System Plan, subject to performance criteria approved by the Commission."[314] We agree with the Company that § 40-2-132.5(7)(b)(III), C.R.S., sets forth a second potential path to GMAC recovery for those activities which the

[314] Hr. Ex. 101, Ihle Direct, p. 61.

Commission finds do not strategically benefit state goals. However, § 40-2-132.5(7)(b)(III), C.R.S. puts important limitations on this second path to GMAC recovery. First, recovery pursuant to § 40-2-132.5(7)(b)(III), C.R.S., is only available if the utility "meets the criteria established in the performance-based framework approved by the commission pursuant to subsection (5)(e) of [§ 40-2-132.5, C.R.S.] through the distribution system planning process for these projected distribution activities." Second, recovery pursuant to § 40-2-132.5(7)(b)(III), C.R.S. is discretionary—it "may" occur through the GMAC if approved by the Commission.

258. In addition to the GMAC provisions of § 40-2-132.5, C.R.S., the Commission keeps in mind that within the adjudicatory process, the utility ultimately holds the burden to demonstrate that expenses are reasonable before they can be included in rates. *See Colorado-Ute Elec. Ass'n, Inc. v. Pub. Utils. Comm'*, 602 P.2d 861, 865 (Colo. 19) (holding Commission "is not charged with the burden of showing" why expenses should be excluded but rather "it is the responsibility of the utility to show that an expense will benefit ratepayers"). The utility's burden is a preponderance of the evidence, and it maintains that burden throughout the proceeding. *See* §§ 24-4-105(7) (outlining burden in agency adjudications), 13-25-127(1) (establishing "preponderance of the evidence" burden in civil actions) C.R.S. (2025); 4 CCR 723-1-1500 (specifying utility bears burden of proof in rate case). This standard requires the fact finder to determine whether the existence of a fact is more probable than not. *Swain v. Colo. Dep't of Revenue*, 717 P.2d 507, 508 (Colo. App. 1985). A party has met this burden when the evidence, on the whole, tips in its favor. *Schocke v. Dep't of Revenue*, 719 P.2d 361, 363 (Colo. App. 1986). If the evidence weighs evenly, the question must be resolved against the party with the burden of proof. *Id*.

259. With this framework in mind, we find it appropriate to determine on a category-by-category basis, whether the record before us supports inclusion of related budgets in the GMAC for this plan period.

(2) GMAC Eligible Cost Categories

260. Because we find that the statute would be best effectuated by analyzing discrete categories for inclusion in the GMAC, we decline to adopt Staff's proposal to apply a $25 million revenue requirement cap to the GMAC. While we agree with Staff that the DSP statute emphasizes "affordability" as a component of GMAC eligibility, we find that the overall statutory framework is not best implemented by a hard recovery cap. We also agree with the Company that the Legislature could have established a retail rate impact cap for the GMAC but did not. We find that § 40-2-132.5(7)(a), C.R.S. contemplates a framework in which the Commission analyzes if discrete investments are "strategic and affordable" and is not best effectuated through an overall cap on recovery.

261. As proposed by the Company and supported by Staff, we authorize Public Service to recover AVPP administration costs through the GMAC. This inclusion is consistent with § 40-2-132.5(8)(f), C.R.S.[315]We also authorize Public Service to roll the TCA-D revenue requirement and associated true-ups into the GMAC. We agree with Public Service that there is benefit in consolidating distribution costs receiving rider recovery together, and see the inclusion of distribution costs in the Transmission Cost Adjustment as a largely temporary solution prior to GMAC implementation. However, noting that the specific rider in which these costs are recovered

[315] A qualifying retail utility shall recover costs to facilitate a virtual power plant program, including foundational technology costs or investments, operations and maintenance expenses, operating technology costs or investments, and information technology costs or investments, through the grid modernization adjustment clause.

does not have a material impact on ratepayers or the Company, and that the costs will get rolled into base rates in the Company's next rate case regardless, we would be amenable to the Company retaining these costs in the TCA-D to the extent there are timing or procedural difficulties with rolling the costs into the GMAC.

262. We additionally authorize Public Service to roll the EADA revenue requirement into the GMAC, capped at the budgeted amounts proposed by Public Service in this Proceeding. We do not institute the $52 million cap proposed by Staff. Similarly to the TCA-D, we see advantages to grouping those distribution costs receiving rider recovery into a single mechanism. However, the Company's EADA investment should be no higher than necessary based on annual usage patterns of specific equipment types and the delivery duration of that equipment and capped at a not-to-exceed amount as shown in the documents presented in the December 3, 2025, Technical Conference (filed on November 10, 2025). To further ensure this, we require the Company to provide in its next DSP, an analysis that indicates the five-year historic and five-year expected deployment rates for major equipment types and the current and proposed stockpile levels funded through the EADA.

263. We approve labor and O&M costs to flow through the GMAC, capped at the amounts included in the filing of additional information provided on November 10, 2025 in this Proceeding. We agree that personnel are an essential part of achieving state policy goals. We have seen with the Company, in other instances, personnel cuts that appear to have resulted in deteriorated performance; in this context, we particularly emphasize the true-up component of the GMAC, and that if the amount of personnel and expense proposed is not actually achieved, these amounts should be trued up, with the appropriate carrying charge. We further clarify that any

amounts presented as O&M in this proceeding thus far should indeed be included as O&M expense if spent, and should not be capitalized.

264. As recommended by Staff, we require additional reporting on labor costs, including ongoing information on capital and O&M splits as presented in Attachment JJP-5C as well as information on total levels of DSP-related staffing in addition to incremental additions. We also limit recovery of labor costs in the GMAC consistently with limitations on labor costs approved in the Company's most recent electric rate case, including restrictions on Annual Incentive Plans and Long-Term Incentive, among others.

265. The remaining proposed categories of projected distribution activities fall into the Company's proposed Type 1 / Type 2 framework.

(3) Proposed Type 1 Investments

266. As discussed above, pursuant to § 40-2-132.5(7)(b)(I), C.R.S., the Commission must determine whether a projected activity "strategically and affordably" furthers a legislative priority before such activity can be recovered through the GMAC. As many parties have pointed out, neither term "affordably" or "strategically" are defined by SB 24-218 or the Commission's Rules. However, parties offer many suggestions on how to discern what is "affordable" and "strategic" within this Proceeding. Public Service does not seem to define the terms explicitly but adds in its SOP that "[w]ith respect to affordability, the Company's proactive planning process results in affordable solutions to meet the identified need by efficiently deploying capital and iterating on an annual basis to ensure capital is only deployed if and when needed. This results in the best long-term value for customers and creates opportunities for customers to electrify, use DERs, or expand operations and invest. It would be short-sighted to merely analyze short-term bill

impacts to assess affordability of the presented budgets."[316] When asked to define "strategic," Ihle provided the following definition at hearing: "That is a great question. And it goes to what strategy means, which I actually looked up yesterday. There are a lot of definitions of that. But I take the general thrust of strategy to be planning a system for a longer-term set of outcomes, and planning for outcomes that are integrated with a broader scope of activity. I think strategy in this case could be defined by both of those two elements, both the somewhat longer-term aspect to it, and also the integration into a larger framework of related activity."[317]

267. CEO also notes that neither statute nor the DSP rules define what "affordably" or "strategically" mean, leaving that determination to the Commission's discretion. CEO asserts that for a distribution activity to "affordably" benefit or advance the statutory criteria and be in the public interest, the activity should seek to achieve statutory outcomes (*e.g.*, enabling beneficial electrification) at the lowest reasonable cost to customers; provide reasonable budget certainty; enable customer access to grid benefits; strive to balance the impact of DSP investment with expected bill impacts from other proceedings; and ensure that the timing of investments and procurement matches need. Further, the Commission should work to ensure that customer electric bills remain at a level that makes it possible for customers to adopt beneficial or transportation electrification. For an activity to satisfy the "strategically" requirement and be in the public interest, CEO argues the distribution activity should maximize utilization of the system through the incorporation of flexible interconnection policies and demand management; encourage the integration of non-traditional and cost-effective solutions (*i.e.,* VPPs, Targeted Demand Areas, and NWAs); enable access and support to beneficial load growth, such as from affordable housing

[316] Public Service SOP at pp. 8-9.
[317] Hr. Tr. August 25, 2025, pp. 128:16-129:2.

development and electric vehicle charging; leverage economies of scale; incorporate standard equipment that can be reallocated to different parts of the system if higher priorities arise; and address multiple risks or issues efficiently, especially when undertaking new capacity investment projects.[318]

268. WRA highlights that at hearing, Company witness Ihle defined strategy to be "planning a system for a longer-term set of outcomes, and planning for outcomes that are integrated with a broader scope of activity."[319]

269. UCA argues that the Commission should recognize that "its statutory mandate to implement the GMAC if it affordably or strategically advances specific goals provides the discretion necessary to modify the GMAC in line with the public interest. The Legislature did not target a wholesale change to how distribution investments are made and costs are recovered. Instead, they envisioned targeted cost recovery to incentivize certain investments to further specific state policy goals."[320] Regarding strategic, UCA states that the "affordably and strategically" standard is a materially higher bar than the "affordably and reliably" standard used in subsection 5(a). UCA argues that the Commission has significant discretion to determine what is affordable and strategic for investments made to modernize the distribution grid, and one way it can measure what constitutes a strategic investment is through the use of reliability metrics. A strategic investment in the distribution system appropriate for GMAC recovery is one that improves customer reliability in a planned and deliberate way.[321]

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318 CEO SOP at p. 22.
319 WRA SOP at p. 6.
320 UCA SOP at p. 19.
321 UCA SOP at p. 23.

270. While we do not adopt a definition of either "strategic" or "affordable" here, we keep these party interpretations in mind while determining if the Company's proposed Type 1 investment categories must receive GMAC recovery. The Company proposes that capacity projects, asset health and reliability projects, informational and operational technology investments, and certain AGIS investments; undergrounding projects; EADA (discussed above); WMP projects, to the extent they were not recovered outside of the GMAC;[322] and incremental O&M projects, related to incremental staffing needs and community outreach are all "Type 1" investments.

271. Regarding capacity expansion, we find that the Company has generally met its burden to show its proposed capacity expansion activities and related budgets affordably and strategically benefit and advance state goals as outlined in the statute, although we understand and are sympathetic to the concerns raised by Commissioner Gilman that led her to dissent.[323] This category includes capital investments associated with upgrading or increasing distribution system capacity. The Company states that "this additional capacity is provided by constructing new substations and installing new or upgraded substation transformers and/or distribution feeders."[324] As noted above, almost all parties supported the Company's proposed capacity budget and its inclusion within the GMAC.

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[322] In the Company's rebuttal case, wildfire costs are characterized as "handled via other regulatory forums;" Hr. Ex. 121, Ihle Rebuttal, p. 18. Accordingly, no WMP projects are approved or discussed further in this Decision.

[323] Commissioner Gilman dissents because she would find that the Company did not support GMAC recovery of its entire proposed capacity budget in large part because the forecasting provided by the Company did not demonstrably meet the "strategic" requirement through the use of load shapes and assumptions that incorporate overly broad assumptions and lack any obvious strategy to orient such load additions to be beneficial to the grid or do so in an affordable way, which were priorities clearly identified in the underlying statute.

[324] Hr. Ex. 104, McDermott Answer, p. 14.

272. We generally agree with the Company that such activities should be considered Type 1 (or mandatory for GMAC inclusion pursuant to § 40-2-132.5(7)(b)(II), C.R.S.) because these capacity projects "support a wide array of identified State goals, including increased capacity in DI Communities, beneficial and transportation electrification, and the increased adoption of DERs[325], although again we understand and are sympathetic to the concerns that led Commissioner Gilman to dissent.[326] We find that within this DSP, the Company has generally supported its position that these capacity expansion investments will further the broad purposes of SB 24-218. As discussed above, because much of the capacity expansion needs are rooted in existing system needs and actual capacity checks the Company has received, we find that these investments are sufficiently strategic and affordable ways to ensure expanded access to timely energization and BE in the near future. However, as proactive DSP planning evolves, the Company will need to demonstrate more strategic approaches to increasing capacity, including better utilization of BE resources to reduce system impacts of new load and strategic uses of non-traditional alternatives to demonstrate that a proposed capacity expansion project is "strategic and affordable." That said, for this DSP, we find the Company's entire capacity expansion proposed activity and budget category is eligible for GMAC recovery. Consistent with this finding, any activities in the Company's "Tools and Communications Equipment" that supports the "capacity expansion" activities should be recovered through the GMAC consistent with § 40-2-132.5(7)(b)(II), C.R.S., at levels not-to-exceed the amounts identified in the November 20, 2025 Technical Conference.

[325] Hr. Ex. 101, Ihle Direct, p. 64.

[326] Commissioner Gilman dissents because she would find that the Company did not support GMAC recovery of its entire proposed capacity budget in large part because the forecasting provided by the Company did not demonstrably meet the "strategic" requirement through the use of load shapes and assumptions that incorporate overly broad assumptions and lack any obvious strategy to orient such load additions to be beneficial to the grid or do so in an affordable way, which were priorities clearly identified in the underlying statute.

273. The Company also proposes to include its "asset health and reliability" proposed activities and corresponding budgets in the GMAC as a "Type 1" activity. The Company defines this category as investments related infrastructure that is "reaching the end of its useful life or is experiencing higher failure rates – and that, as a result, will negatively impact reliability of service. 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."[327] The Company argues that asset health and reliability investments should be considered Type 1 (or mandatory for GMAC inclusion pursuant to § 40-2-132.5(7)(b)(II), C.R.S.,) because they are connected to "preserving existing capacity" and "so that the existing system does not degrade, especially as new additions are made to it."[328]

274. However, some parties argue that inclusion of asset health and reliability within the GMAC is inappropriate. CEO argues that inclusion in the GMAC should require a showing that a project or investment "directly increases reliability or resilience" for GMAC eligibility.[329] Similarly, WRA argues that Public Service has not demonstrated that the Asset Health and Reliability portfolio materially benefits or advances state goals because the statute requires "increased reliability" and "increased resiliency" but does not identify maintaining or preserving reliability.[330] WRA argues that the Commission should not afford Type 1 GMAC recovery to investments intended "just to keep the status quo," as such investments do not contribute toward the state goals enumerated in § 40-2-132.5(7)(b)(I), C.R.S.[331] WRA also argues that the Company

[327] Hr. Ex. 106, Bloch Direct, p. 9; *see also* Table KAB-D-1.
[328] Public Service SOP at p. 7.
[329] Hr. Ex. 400, Durkay Answer, p. 28.
[330] WRA SOP at pp. 4-5.
[331] WRA SOP at p. 5.

has not demonstrated that its proposed asset health and reliability investments are "strategic" because the Company has no specified set of longer-term outcomes for the Asset Health and Reliability category, so there is no yardstick on which the Commission could measure whether this body of work is strategic.[332]

275. We agree with WRA and others that the Company has failed to sufficiently delineate between Asset Health and Reliability investments that meet the objective of increasing reliability or resiliency, versus those investments that occur in the ordinary course of business to maintain service to customers. Because the Company has not met its burden to support that its proposed investments actually "increase reliability" as required by § 40-2-132.5(7)(b)(I), C.R.S., the Commission cannot determine whether such activities "strategically and affordably" further a legislative priority. As such, these activities are not eligible for GMAC recovery pursuant to § 40-2-132.5(7)(b)(II), C.R.S.

276. The Commission's determination that the Company failed to show its Asset Health and Reliability investments will increase reliability is supported by the record in this Proceeding. For example, the Company stated in a discovery response that "the majority of investment in this category is intended to prevent deterioration in reliability performance."[333] In testimony, the Company stated: "this work is intended to mitigate degradation, not to provide improvement."[334] More generally, the Company provided no quantitative analysis showing reliability improvements

[332] WRA SOP at p. 6.
[333] Hr. Ex. 1700, Att. CV-14 [WRA 2-2].
[334] Hr. Ex. 125, 30:19-22. At hearing, this was characterized as a "typo" but is still largely corroborated throughout, including in the Company's SOP at p. 7 (…"the Company must ensure that the system is healthy by more proactively investing in Asset Health and Reliability programs and projects so that the existing system does not degrade, especially as new additions are made to it").

from proposed asset health and reliability budget,[335] nor made any attempt to correlate its proposed budget with areas of the system with known reliability issues.

277. Finally, the Company's proposal that virtually all routine replacement of distribution equipment qualifies for mandatory recovery though the GMAC is inconsistent with the prescriptive framework outlined by the Legislature in § 40-2-132.5(7), C.R.S. Had the Legislature meant for all ordinary course routine spending to flow through the rider, it could have set up such a statute. Instead, the Legislature tasked the Commission with taking a hard look at proposed activities before affording the Company highly advantageous accelerated cost recovery for routine investments. To read the DSP statute to require GMAC recovery for any investment that "maintains" system reliability could lead to absurd results. It is clear that the Legislature intended by its use of the terms "increase," "strategically," and "affordably" to set a higher bar before inclusion in the GMAC than the Company suggests. As such, for this DSP, we find that the Company has not met its burden to show that its proposed asset health and reliability investments and associated budgets necessitate GMAC recovery pursuant to § 40-2-132.5(7)(b)(II), C.R.S.

278. Consistent with the reasoning above, we also find that the Company did not meet its burden to show that Community-directed ungrounding projects necessitate GMAC recovery pursuant to § 40-2-132.5(7)(b)(II), C.R.S. The Company acknowledged that the reliability benefits of undergrounding lines when there's been no reliability issues with the overhead lines themselves are "very slim."[336] Also, the Company's "Tools and Communications Equipment" that supports the "asset health and reliability" activities should not be recovered through the GMAC consistent

[335] Hr. Ex. 602, Konidena Answer, pp. 105-107.
[336] Hr. Tr. August 28, 2025, pp 263-264.

with § 40-2-132.5(7)(b)(II), C.R.S., for the same reasons outlined above, nor should AGIS-related investments, which were largely discussed in the context of supporting reliability.

279. In sum, the Commission finds that the Company has met its burden to show that capacity-related investments strategically and affordably further the purposes of SB 24-218 and may be recovered through the GMAC in 2026, 2027, and 2028 through the process discussed below (Section G).

(4) Proposed Type 2 Investments

280. The Company proposes several categories of "Type 2" distribution activities that would be included in the GMAC subject to performance-based framework. As described by the Company, examples of Type 2 activities would include: Extensions for new service if those extensions do not serve policy goals (*i.e.,* new business); relocation of distribution infrastructure that would not result in increased capacity, reliability, or resilience; streetlighting investments; and investments in fleets and tools that are not necessary to support increased capacity, reliability, or resilience.[337] As discussed above, numerous parties oppose the Company's "Type 2" proposal. Several argue for more stringent performance-based frameworks and for better linkage between the proposed activities and the performance improvements expected in SB 24-218.

281. Pursuant to § 40-2-132.5(7)(b)(III), C.R.S., the Commission retains discretion to allow for recovery of proposed distribution activities that do not further state goals through the GMAC. While the Commission may not allow for activities that do not meet the performance-based framework established pursuant to § 40-2-132.5(5)(e), C.R.S. to be recovered through the GMAC, the Commission retains all other discretion to allow for GMAC recovery pursuant to § 40-2-132.5(7)(b)(III), C.R.S. By making § 40-2-132.5(7)(b)(III), C.R.S.,

[337] Hr. Ex. 101, Ihle Direct, p. 66.

discretionary (*i.e.,* recovery "may occur" through the GMAC), the Legislature ensured that the Commission retains its fundamental authority to determine appropriate cost recovery mechanisms for all activities that fall outside those activities the Legislature specifically sought to encourage through § 40-2-132.5(7)(b)(II), C.R.S. Thus, we find that § 40-2-132.5(7)(b)(III), C.R.S. gives the Commission significant discretion as to which distribution activities receive GMAC recovery under the performance-based framework established by the Commission, as well as how that recovery should occur.

282. Accordingly, we find that not all distribution activities which are not found to affordably and strategically benefit or advance state goals should go through the GMAC, even under the performance-based framework; rather, we find it appropriate to look at the distribution activities included in the Company's DSP, both individually as well as a collective, to determine the appropriate amount of GMAC recovery that should be attainable by the Company should it meet the requirements of the performance-based framework.

283. Considering this discretion, which allows the Commission to determine which distribution activities for which recovery "may occur" through the GMAC, we find that a not-to-exceed budget of $100 million for non-capacity distribution activities in 2027 and $200 million for non-capacity distribution activities in 2028 are eligible for GMAC recovery and would, critically, maintain affordability, contingent on the development of a holistic and comprehensive set of criteria discussed below.

(a) Performance-Based Framework

284. Section 40-2-132.5(5)(e), C.R.S. sets forth that a DSP must include a performance-based framework, which must "consist of: (I) Applicable interconnection timelines; (II) Applicable energization timelines, so long as: (A) The energization timelines are not applicable

to the first distribution system plan filed after May 22, 2024; . . . (III) Reasonable and cost-effective targets measured in megawatts for flexible load and demand management, so long as: (A) A general target-setting framework must be evaluated in the first distribution system plan filed after May 22, 2024 and further developed through other planning processes, including subsequent distribution system plans, electric resource plans, and demand-side management plans; and (B) The targets are applicable in the second distribution system plan filed after May 22, 2024 and subsequent distribution system plans. Pursuant to § 40-2-132.5(7)(b)(III), C.R.S., the Commission may only allow for recovery through the GMAC for those activities that do not meet the standards of § 40-2-132.5(7)(b)(I), C.R.S., if the Commission finds that the activities meet the criteria established in the performance-based framework approved by the Commission pursuant to subsection (5)(e).

285. Public Service argues that the list set forth in § 40-2-132.5(5)(e), C.R.S., is an "exclusive" list and therefore the Commission cannot add any criteria to the performance-based framework. It argues that for this DSP, the only relevant criteria is the establishment of the interconnection framework contemplated by § 40-2-132.5(5)(e)(I), C.R.S. WRA and others argue that § 40-2-132.5(5)(e), C.R.S. sets the "floor" of what can be included in the performance-based framework and that the Commission retains discretion to add additional criteria. We find that it is appropriate to condition recovery pursuant to § 40-2-132.5(7)(b)(III), C.R.S., on more metrics than just those found in § 40-2-132.5(5)(e), C.R.S. While the performance-based framework in § 40-2-132.5(5)(e), C.R.S., sets the Legislature's priorities, the Commission, through its discretion inherent in to § 40-2-132.5(7)(b)(III), C.R.S. may establish more criteria as necessary to ensure that funds recovered through the GMAC further legislative priorities. We agree with WRA that the list of performance screens in § 40-2-132.5(5)(e), C.R.S. sets a *minimum* floor for recovery

through § 40-2-132.5(7)(b)(III), C.R.S., and note that the state policy goals outlined throughout SB 24-218 include increased reliability, creating more resiliency, dynamically integrating supply and demand in real time, improved customer service, and several other goals beyond those directly related to the performance screens outlined in SB 24-218.

286. To that end, we find that more process is required before we can allow for any recovery pursuant to § 40-2-132.5(7)(b)(III), C.R.S. Through Decision No. C25-0666-I, the Commission prompted parties on whether a framework should be developed to track progress in certain metrics for implementation through the GMAC. Many of the parties replied with tentative support for the idea but argued that through SOPs was not the proper venue for developing such a framework. We agree that the record before us does not allow us to develop a workable framework without more party input. We anticipate that the rulemaking contemplated by § 40-2-132.5(6), C.R.S. as well as the prompts for additional comments within this Proceeding (*See* Section J below) will both provide a forum to get a framework established. We decline, as suggested by several parties, to wait until the rulemaking exclusively because we find that providing the Company with an opportunity before the next DSP to receive greater recovery through the GMAC will motivate and ensure greater performance in meeting legislative priorities of SB 24-218. We expect that the process set forth below, to develop a workable framework for performance as well as mechanical implementation in the GMAC, will ensure that GMAC cost recovery is linked to interconnection time; system reliability (*e.g.*, those metrics required in QSP reports); customer service (*e.g.*, those referenced in Hearing Exhibit 2307 [Staff investigation into customer care]); HCA data availability and usability; availability of a Flexible Interconnection tariff; dynamically integrating demand and supply in real time, and distribution asset utilization (or other metric to incentivize an optimized peak load impact of EV and BE technologies). We find that each of these

are fundamental to furthering the legislative priorities of SB 24-218 and thus necessary to implement before any recovery pursuant to § 40-2-132.5(7)(b)(III), C.R.S.

287. Additionally, based on this discretion afforded to us by (7)(b)(III), we reject the Company's proposed structure of including 100 percent of "Type 2" activities in the GMAC advice letter initially and then clawing back the recovered amounts if the Company fails to meet performance screens in the years of recovery. We largely find that recovery should be contingent on performance, and that it is irrational to grant the Company extraordinary cost recovery at a time when performance in certain key areas the legislation targets has been poor. Additionally, with the size of the GMAC, and demonstrated inconsistency in the Company's performance in several metrics, preemptively including all "Type 2" activities subject to true-up could result in large, complex true-ups, accompanied by sizable interest obligations involving the time value of money.

288. We find it appropriate at this time to reject the Company's proposed use of existing interconnection timing requirements for the interconnection performance screen required by § 40-2-132.5(5)(e)(I), C.R.S. We agree with SWEEP/NRDC and CEO that the requirement should be more stringent than what is already required in the Commission's Rules. We find that a general theme of SB 24-218 is *improved* performance, as discussed by several parties in this Proceeding,[338] and that state goals are not being advanced by simply following existing rules, nor should the Company be rewarded with extraordinary cost recovery simply for doing so. We also note that the Company has already demonstrated the ability to interconnect DERs significantly quicker than the existing rule requires,[339] further underscoring the insufficiency of the proposed screen in incenting improvement, and that the Company has admitted that interconnection timing is likely to improve

[338] *e.g.,* Hr. Ex. 101, Ihle Direct, pp. 8-9; CEO SOP at pp.8-9; SWEEP/NRDC SOP at pp.18-19.
[339] Hr. Ex. 1700, Valentine Answer, p. 54; see also Hr. Ex. 1700, Att. CV-17 / CV-18.

further as a result of HCA developments which are currently overdue to be completed.[340] As part of the performance-based framework discussed elsewhere in the order, we require the Company to file 2025 interconnection information in the same format as CV-18 to inform further development of the performance-based framework.

G. GMAC Mechanics

1. Filing Cadence

a. Public Service Direct

289. As proposed by Public Service, the projected GMAC rate would be filed in a November 1 Advice Letter and effective January 1 of the following year, consistent with SB 24-218.[341]

290. Public Service also proposed that the projected rate would include the true-up for the previous year, which would be filed on April 1. The true-up, as proposed, would include a symmetrical carrying charge applied to 12 months to the over- or under-recovery balance, at the Company's most recently approved WACC.[342] SB 24-218 states that "recovered qualifying distribution activity recovery is subject to a true-up with any positive or negative balance credit to customers or recovered by the qualifying retail utility in the subsequent year and an appropriate financing cost applied to the positive or negative balances."[343]

[340] Hr. Tr. August 28, 2025, p. 217-218. "At a minimum, I can see [HCA automation] shaving a week off, it not more, depending on the level of automation we are able to get from it. So I don't have a hard and fast number, but I would expect a decent amount of savings from a time standpoint for the load and generation interconnection process."

[341] § 40-2-132.5(7)(c)(II), C.R.S.: "A qualifying retail utility shall make a [GMAC] Advice Letter filing with the Commission annually, and no later than November 1 of each year, with an effective date of January 1 of the subsequent year…"

[342] Hr. Ex. 107, Peuquet Direct, p. 11.

[343] § 40-2-132.5(7)(c)(III), C.R.S.

291. Under the Company's proposal, the April 1 true-up filing would also serve as the prudence review for those distribution activities that are recoverable through the GMAC for the prior calendar year, in place of the prudence review that would ordinarily occur in a Phase I rate case. Public Service asserted that this would simplify the transfer of GMAC costs into base rates, allowing parties to concentrate on other issues, and that more timely prudence review would facilitate greater alignment between the Company, the Commission, and other stakeholders on distribution system investments.[344]

b. Party Positions

292. Staff proposes the true-up and annual report filing occur on June 1, rather than April 1 as proposed by Public Service. In addition to annual reporting and the true-up for the previous year (which would then be included in the November 1 advice letter filing), Staff's proposed June 1 filing would also include a preliminary list of activities proposed for GMAC recovery the following year, based on reliability needs established in the April 1 QSP report. This list of activities would allow Staff and other stakeholders to review the proposed investments and discuss concerns prior to the AL filing, with the intent of avoiding litigation of those AL filings.[345]

293. In Rebuttal, Public Service expresses several disagreements with Staff's June 1 "preview" filing concept. The Company asserts that a "preview" filing would require duplicating DSP efforts in a given year, which would take a holistic effort, create administrative burden, and upend the distribution planning cycle; Public Service also notes that the June 1 "preview" filing would not necessarily line up with the actual AL filing, due to needs developed after the June 1 filing that change investment plans. Public Service likens this evolution of planning to many of

[344] Hr. Ex. 107, Peuquet Direct, pp. 9-11.
[345] Hr. Ex. 500, Haglund Answer, pp. 44-45.

the Company's other riders, and notes that the true-up process can be used to review any deviations. The Company also disagrees with Staff that the QSP should be a direct input into the GMAC process.[346]

294. Nevertheless, the Company agrees with Staff's sentiment that avoiding litigation of the November 1 filing would be beneficial to all parties; as such, Public Service would be amenable to work with Staff and other parties to create a process for providing overviews in advance of the November 1 filing.[347]

c. Findings and Conclusions

295. We require the GMAC true-up and annual report filing be made on April 1. We find that an April 1 filing date would allow for more time for overall review prior to the November 1 advice letter filing, compared to the June 1 date proposed by Staff. It is possible that the need for a more formal "preview" filing may become apparent through the further development of performance metrics, but the format and cadence of such a filing, to the extend one is needed, can be determined at a later time. However, we do agree that it would be advantageous for the Company to engage in informal previews with Staff and other parties ahead of the November 1 advice letter filing, to lessen the likelihood of litigation of the November advice letter filing to the extent possible.

296. On December 8, 2025, the Company filed a Redlined Grid Modernization Adjustment Clause proposed Tariff in which it incorporated revisions discussed by the Commission at the technical conference held on December 3, 2025. We require the Company to

[346] Hr. Ex. 126, Peuquet Rebuttal, pp. 7-9.
[347] Hr. Ex. 126, Peuquet Rebuttal, p. 9.

make a compliance advice letter and tariff filing that substantively complies with the December 8, 2025 filing.

2. True-Up Carrying Charge

a. Party Positions

297. Rather than a symmetric carrying charge on under- or over-recovery like that proposed by Public Service, Staff instead proposes an asymmetric carrying charge only to be applied to over-recovered amounts, at the Company's most recently approved WACC. Staff states that this approach would be consistent with the TCA and TEPA true-ups, and that it gives the Company an incentive to avoid over-recovery.[348] Staff particularly highlights that GMAC cost recovery is based on the Company's forecast, the Company's determination of which projects are funded, and the Company's decision of when to purchase equipment.[349] Staff asserts that this approach is consistent with § 40-2-132.5(7)(c)(III), C.R.S., which it says does not mandate symmetrical treatment, only an "appropriate financing costs applied to the positive or negative balances," and characterizes an asymmetric carrying charge as a way to prioritize ratepayer protections.

298. In Rebuttal, Public Service disagrees with Staff's interpretation of § 40-2-132.5(7)(c)(III), C.R.S., instead asserting that a plain language reading of the statute supports a symmetric true-up to either positive or negative balances, which the Company says is "appropriate." Public Service argues that the forecast is assembled based on many factors, and has several uncertainties, many of which are outside the Company's control; the Company also notes that overspending would impact customer bills, financing needs, and could subject the Company

[348] Hr. Ex. 500, Haglund Answer, p. 46.
[349] Staff SOP at p. 16, discussing Hr. Tr. September 2, 2025, pp. 85-86.

to additional regulatory risk. Public Service asserts that the purpose of a true-up is to make sure that customers pay the right amount while also making the Company whole, and cites to benefits of fairness, stability, and accounting for the time value of money; the Company additionally notes that several riders have symmetric carrying charges, including the WMP and Renewable Energy Standard Adjustment, among others.[350]

299. As an alternative recommendation for carrying charges on the true-up balance, Public Service proposes no carrying charge for either over- or under-recovered amounts in the GMAC for the first two years of its existence. The Company calls this a middle ground approach, with symmetric treatment, and would allow for two years of evaluation of the GMAC prior to reevaluation of carrying charges in future GMAC filings.[351]

b. Findings and Conclusions

300. We adopt an asymmetric carrying charge, with a carrying charge on over-recovered amounts at the Company's most recently authorized WACC and no carrying charge on under-recovered amounts, as recommended by Staff. We agree with Staff that § 40-2-132.5(7)(c)(III), C.R.S., does not require symmetrical treatment, and that an "appropriate" financing cost can differ between the positive and negative balances We agree that this method prioritizes ratepayer protections, and reflects the asymmetric information between the Company and ratepayers when the developing projected rates and is consistent with current treatment the TCA-D.

[350] Hr. Ex. 126, Peuquet Rebuttal, pp. 12-15.
[351] Hr. Ex. 126, Peuquet Rebuttal, pp. 15-16.

3. Prudence Review

a. Party Positions

301. Staff opposes the Company's proposal to use GMAC filings as the prudence review for GMAC costs; Staff instead asserts that prudence review should occur during a Phase I rate case, when GMAC costs would be rolled into base rates. Staff states that waiting until a rate case for prudence review would be consistent with the approach taken with the TCA, and characterizes the GMAC filings as "isolated."[352] UCA also recommends prudence review not occur until a Phase I rate case, stating that having prudence review in the April 1 filing would increase the burden on intervenors to monitor the proceeding[353] and that rate case review would ensure costs are reviewed holistically.[354]

302. In Rebuttal, Public Service asserts that including the prudence review within an electric base rate case would stifle the isolated review of GMAC costs, which would result in less focus and transparency on those costs. In the context of Staff's proposals specifically, the Company also notes that the proposed cap on the GMAC and inability to reset the cap outside of a base rate filing would result in more rate cases, which would lead to inefficiencies.[355]

b. Findings and Conclusions

303. We find it appropriate to conduct prudence review for GMAC costs in a Phase I rate case, rather than the true-up filing. We agree with Staff and UCA that it is advantageous to review costs on a more holistic basis, particularly with some ongoing distribution spending

[352] Hr. Ex. 500, Haglund Answer, p. 45.
[353] Hr. Ex. 601, Villarreal Answer, p. 35.
[354] Hr. Tr. September 3, 2025, p. 97:14-19.
[355] Hr. Ex. 121, Ihle Rebuttal, pp. 45:15-46:14.

continuing to receive traditional base rate recovery rather than extraordinary rider recovery, and find that requiring review in the true-up filing could add further complications to that filing.

4. New Projects

a. Party Positions

304. CEO recommends that the Commission reject the Company's proposal to allow GMAC eligibility determination to occur in the annual Advice Letter filings, noting that those filings have a relatively abbreviated timeframe for review. Instead, CEO would have the determination of each distribution activity occur only within litigated DSPs, and would have the Commission clarify that any distribution activity not directly approved in the instant DSP could not be included in an interim November AL filing for GMAC cost recovery.[356]

305. In Rebuttal, Public Service describes CEO's proposal as "premature and legally questionable, at best." While the Company acknowledges the DSP is the primary venue to establish projects, it describes distribution planning as an iterative process, and states it does not want to lock out emergent system needs from future inclusion.[357] Public Service also states that flexibility on exact projects would be similar to other riders the Company has in place, and that the true-up process is the appropriate venue to review the actual work completed and deviations from estimates.[358]

b. Findings and Conclusions

306. We deny CEO's proposal and instead find it appropriate to allow new projects to be included in the annual Advice Letter filings, to the extent these new projects are consistent with the categories allowed and continue to be subject to the caps established elsewhere in this order.

[356] Hr. Ex. 400, Durkay Answer, p. 22:7-16 and p. 31:5-11.
[357] Hr. Ex. 121, Ihle Rebuttal, pp. 63-64.
[358] Hr. Ex. 126, Peuquet Rebuttal, p. 9.

We acknowledge the possibility of emergent needs in the distribution planning process and the need for a certain level of commercially reasonable and good-faith flexibility with projects. To the extent there are material changes to projects, we highly recommend these changes to be previewed with parties in advance of the Advice Letter filings. That is, we believe it would be advantageous for the Company to engage in informal previews with Staff and other parties ahead of the November 1 advice letter filing in order to lessen the likelihood of extended litigation to the extent possible.

307. We also recognize that specific projects submitted through the Advice Letter filings may not align exactly with this DSP. However, we find it necessary that the revenue requirements established in this Decision represent "caps" to total recovery through GMAC. These figures are established as the values confirmed at the December 3, 2025 technical conference.

5. Cost Allocation and Rate Design

a. Company's Direct Case

308. Public Service largely proposed to allocate cost components of the GMAC across classes consistently to how similar costs have been allocated in past cases. The GMAC will incorporate costs across several functions, including distribution substations, primary distribution, secondary distribution, service laterals, and metering; Public Service proposed to allocate those functions using the methodologies for each function authorized in its most recent Phase II rate case, Proceeding No. 23AL-0243E. The Company asserted that using these methodologies would maintain consistency with the treatment of those functions for existing costs and prevent large class-specific rate impacts when costs eventually roll into base rates.[359]

[359] Hr. Ex. 107, Peuquet Direct, pp. 33-35.

309. Additionally, Public Service proposed that the Phase II allocators be modified using a growth factor for each customer class based on forecasted kWh sales relative to the actual kWh sales from the Phase II proceeding, which it stated would be consistent with the methodology used in the Company's Purchased Capacity Cost Adjustment ("PCCA"), Demand-Side Management Cost Adjustment ("DSMCA"), as well as the TCA-D. Certain costs within the GMAC have not been functionalized, including EADA costs, general plant costs, and some O&M costs; these costs would effectively be prorated across all customer classes based on the class allocation of all other functionalized costs.[360]

310. Under the Company's proposal, GMAC rates would be structured similarly to other non-base rate cost adjustments, with Residential and Small Commercial customers being billed on an energy basis ($/kWh), and Commercial & Industrial customers billed on a demand basis ($/kW). The Company would utilize forecasted billing determinants for the 12-month rate period that each GMAC rate will be in effect for rate calculations. The GMAC rates would apply to all customer classes that take service at distribution voltage; however, the Company proposed to exempt standard Economic Development Rate ("EDR") customers from paying the GMAC. The Company asserted that the EDR rates are designed to recover marginal costs, and that charging the GMAC to those customers would not be necessary to recover those marginal distribution costs; additionally, it stated that this exemption would be consistent with other riders, including the PCCA and TCA.[361]

[360] Hr. Ex. 107, Peuquet Direct, pp. 35-37.
[361] Hr. Ex. 107, Peuquet Direct, pp. 37-38.

b. Answer Testimony

311. SWEEP/NRDC recommend that the GMAC use the allocators approved in the Company's last Phase II rate case, without any adjustments for sales changes. SWEEP/NRDC assert that doing this would align cost allocation more closely with existing base rates, and would not rely on uncertain forecasted data. SWEEP/NRDC express concerns that the Company's proposed cost allocation methodology would not result in forecasted sales data being trued up to actual sales. And while Public Service compared the proposed cost allocation methodology to that of the PCCA and DSMCA, SWEEP/NRDC assert that those riders are designed to recover costs for activities that are not historically recovered in base rates, while the GMAC would be recovering costs that otherwise *would* be included in base rates.

c. Findings and Conclusions

312. We agree with SWEEP/NRDC's recommendation and require the Company to use the allocators from the last Phase II rate case, without any adjustments. We are wary of the challenges with the sales forecast seen in this and other proceedings. The allocators from the previous rate case have been adjudicated by the Commission, and the use of these allocators promotes rate stability, in contrast to forecasts which are subject to fluctuation.

313. We additionally direct Public Service to investigate the use of AMI data to develop more precise allocation methods for distribution costs in future proceedings.

H. Hosting Capacity Analysis

1. Background

314. The Company is required by statute and Commission rule to develop hosting capacity analyses ("HCAs") and maps ("HCA maps") and the Commission is required to consider these maps and analyses in the DSP. Commission Rule 3527(k) defines hosting capacity as "the

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."

315. There are two types of Hosting Capacity Analyses and associated HCA maps at issue in this Proceeding, generation and load HCAs. Generation HCAs are used to help identify locations to interconnect generation resources, such as rooftop solar or Community Solar Gardens. Load HCAs provide information on loading on feeders, and can be used to help inform customer decisions regarding new or expanded facilities that would increase load.[362] Generation maps are provided in blurred format on the Company's website; unblurred maps are available through a secure web portal upon access approval as well as the signing of a non-disclosure agreement ("NDA"). Load HCA maps are only made available in this Proceeding to certain intervenors through the Commission's Highly Confidential data protections. Public Service supports maintaining the existing confidentiality of HCA data in this Proceeding.

316. Parties assert HCAs and HCA maps can be extremely useful. In its Rebuttal Testimony, the Company notes that HCA data allows developers to make better decisions about locating load and generation.[363] ACE states that project developers can use HCA maps for siting purposes, avoiding upgrade costs by targeting less saturated areas and reducing the number of report submissions needed, which can be costly for stakeholders, ratepayers, and the Company.

[362] Hr. Ex. 123, McDermott Rebuttal, p. 33.
[363] Hr. Ex. 130, Marion Rebuttal, p. 8.

ACE further asserts that maps can help with distribution system planning, drawing investment to areas where the grid can support them, and ensuring upgrades are utilized well.[364] IREC witness McKerley quotes developers as describing HCA maps as "gold" and using them "religiously" when available.[365] Drawing on testimony from McKerley and Mafazy, IREC explains how HCA maps are used for siting decisions and how they could be employed by the Commission—for example, to better target upgrades in disproportionately impacted communities or to align transportation-electrification forecasts with anticipated grid-upgrade locations in support of Colorado's EV-adoption goals[366]

2. Security

a. Generation HCA

317. Generation maps, as well as some limited generation data, are provided in blurred format on the Company's website. To access the unblurred map, which allows visibility into the individual lines and their hosting capacity statistics, users are required to fill out an access request form, sign a custom non-disclosure agreement ("NDA"), and then, if approved, sign in through a secure web portal to see the information. Although the blurred map does provide information on individual feeders through popup boxes, this data can only be downloaded in *tabular* format through the secure web portal after signing the NDA.[367]

318. The 2022 DSP Settlement Agreement, which was approved by the Commission in Decision No. R23-0080, included a provision allowing for access to the non-blurred maps only upon execution of an NDA.[368] However, that settlement also included a term allowing the Settling

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[364] Hr. Ex. 900, White Answer, pp. 13-15.
[365] Hr. Ex. 801, McKerley Answer, p. 8.
[366] Hr. Ex. 800, Mafazy Answer, pp. 9-13; Hr. Ex. 801, McKerley Answer, pp. 8-15.
[367] Hr. Ex. 123, McDermott Rebuttal, p. 34; Hr. Ex. 130, Marion Rebuttal, p. 10.
[368] R23-0080, Attachment A – Settlement Agreement, ¶ 36.2.

Parties to make any recommendation on data access and security that they choose in future proceedings.[369]

(1) **Party Positions**

319. Several parties in this Proceeding argue that the required NDA is problematic. Some recommend that the Commission require modifications to the NDA, while others recommend it be eliminated altogether. Parties' arguments against the currently existing NDA take several forms.

320. UCA recommends making the HCA data public. UCA asserts that Public Service has not provided sufficient evidence to warrant the confidentiality of the HCA data. UCA characterizes the Company's security warnings as "unsubstantiated," and states that the Company has not provided the Commission with actionable evidence that supports restricting grid data.[370] UCA contrasts Public Service's treatment of HCA data with that of several other utilities, including PEPCO, whose websites contain public maps showing locations of and information about feeders in the U.S. Capitol area and other potentially sensitive areas, and PG&E, whose website contains maps near the San Francisco International Airport.[371]

321. ACE recommends making the HCA data public. ACE highlights several NDA clauses, including paragraphs 6[372] and 10[373] that it claims subject signatories to "significant

[369] R23-0080, Attachment A – Settlement Agreement, ¶ 41.

[370] UCA SOP at p. 26.

[371] Hr. Ex. 601, Villarreal Answer, pp. 26-29.

[372] Hr. Ex. 900, Att. JW-2, paragraph 6; "Requestor acknowledges that the extent of damages in the event of breach of any provision in this Confidentiality Agreement would be difficult or impossible to ascertain, and that there will be no adequate remedy at law in the event of any such breach."

[373] Hr. Ex. 900, Att. JW-2, paragraph 10; "safeguards shall include, without limitation, a written data security plan, employee training, information access controls, restricted disclosures, systems protections (*e.g.*, intrusion protection, data storage protection and encryption, and data transmission protection and encryption), secure software development processes, and appropriate physical security measures."

liability" and impose overly burdensome security requirements. ACE asserts that small or medium size companies may not have the infrastructure to meet these security requirements.[374] ACE asserts that "no other utility in the U.S. requires NDAs to access HCA data," and claims that Public Service has not identified any actual, documented threat from the release of HCA maps. ACE also states that no technical barriers or monitoring exist to prevent anyone from signing the NDA, thus potentially making the NDA ineffective as a true barrier and instead only serving as a chilling effect on legitimate use of the HCA.[375]

322. ACE also argues that the NDA is inconsistent with the Commission's Rules. ACE notes that in the 2020 DSP rulemaking, Proceeding No. 20R-0516E, the Commission declined to authorize the implementation of NDAs for web portals, expressing concern over their impracticality for developers who must work with clients.[376] Subsequently, the Commission adopted Rules 3531(F) and 3541, requiring utilities to publish HCA maps and data to the public web portal. ACE additionally points to Commission Rule 3541(b) which only allows denial to its web portal if visitors violate the terms of service.[377]

323. IREC also recommends making the HCA data public. IREC asserts that the Company has failed to support its position that the NDA is justified due to security risks, that the risks are highly speculative, that there are no known instances of attacks using HCA data, and that the Company's citations to standards and reports do not actually create links between classifying data and protecting the grid.[378] IREC asserts that other approaches can provide security, including the authentication already required by the Company as well as more equipment-focused

[374] Hr. Ex. 900, White Answer, pp. 16-17.
[375] ACE SOP at p. 13-14.
[376] Decision No. R21-0387, ¶170.
[377] ACE SOP at pp. 12-13.
[378] Hr. Ex. 801, McKerley Answer, pp. 27-35.

solutions.[379] IREC highlights that much of the HCA data can be found through other publicly available sources, such as Google Maps.[380] IREC notes that NDAs are not required in other states and that other regulatory bodies such as the Federal Energy Regulatory Commission ("FERC") and the California PUC support open grid data,[381] and, like ACE, claims that bad actors would not be stopped by an NDA or its provisions.[382] Like ACE, IREC highlights the unbounded liability created by paragraph 6 of the NDA, but also notes that other NDAs may have provisions that preclude liability for data that is already publicly available, while this NDA does not. IREC also highlights paragraph 13, which prevents signatories from disclosing that they have signed the NDA.[383]

324. IREC claims that requiring an NDA in *any* capacity would be counterproductive because it states HCA data is most useful when shared. Potential examples of beneficial sharing given by IREC include developers and aggregators sharing the data with customers, researchers publishing results on the data, or the Commission using the data to better understand the impact of load growth on the grid. IREC states that a revision could make the NDA more feasible to sign, but still would make the HCA less useful than it otherwise would be, and would still have limited security value.[384]

325. AEU also recommends making the HCA data public and echoes other parties' criticisms that the Company has not provided a specific or compelling rationale for requiring the NDA, has not quantified the increased risk of attacks from availability of HCA data, and has not

[379] Hr. Ex. 801, McKerley Answer, pp. 36-42.
[380] Hr. Ex. 801, McKerley Answer, pp. 21-24.
[381] Hr. Ex. 801, McKerley Answer, pp. 24-27.
[382] Hr. Ex. 801, McKerley Answer, pp. 45-46.
[383] Hr. Ex. 801, McKerley Answer, pp. 46-50.
[384] IREC SOP at pp. 14-17.

cited any studies or reports that recommend limiting access to HCA data. AEU highlights that other utilities provide unrestricted HCA data and that no examples were provided of other utilities requiring an NDA to access HCA data. AEU criticizes the liability put onto signatories of the NDA, as well as the security standards, which AEU says are unreasonable and unworkable for developers, aggregators, and customers.[385]

326. Tesla recommends requiring the use of the "time-tested, appropriately-balanced" NDA used in Commission proceedings rather than the Company's current NDA to access HCA data. Tesla agrees with other parties that the justification for not providing easy access to HCA maps is "dubious" and that the Company's position fails to incorporate and balance public policy objectives. Tesla also agrees with parties that requiring an NDA for this information is more likely to prevent good faith actors from accessing information than bad faith actors.[386]

327. CEO recommends that, should the Commission authorize an NDA in this Proceeding, that the Commission should require the Company to work with parties and other stakeholders to modify the NDA to ensure all appropriate entities are able to sign it. CEO describes the current NDA as "overly restrictive," and asserts that it cannot sign the NDA as it exists currently, particularly due to the indemnity clause.[387]

(2) Company's Rebuttal Case

328. Public Service largely leans on the security concerns of making HCA data public in its Rebuttal Testimony. Public Service portrays the NDA as part of a wider security risk program already in place, including cybersecurity policies structured around National Institute of Standards and Technology framework as well as adherence to FERC and North American Electric Reliability

[385] AEU SOP at pp. 16-21.
[386] Tesla SOP at pp. 16-18.
[387] CEO SOP at pp. 28-29.

Corporation standards, and states that the NDA is one tool among many to reduce risk.[388] The Company asserts that it not only has to protect against types of attacks that have occurred previously, but also novel attacks that could occur in the future.[389] Public Service outlines that NDAs are commonly used for several purposes in utilities and other industries,[390] that the Commission authorized the use of an NDA by approving the 2022 DSP Settlement Agreement, and also granted the Motion for Extraordinary Protection in this Proceeding related to load HCA data.[391] The Company asserts that it would be a "dereliction of its responsibility" to release information just because other utilities do so, and notes that the Commission is not bound by decisions made in other jurisdictions.[392] While Public Service acknowledges that line locations are frequently publicly available, it also notes that underground feeders, which make up a substantial portion of its distribution system, are not visible this way,[393] and asserts that gathering data piecemeal is different from having it together in a central location, combined with loading information.[394]

(3) Findings and Conclusions

329. We require Public Service to make the unblurred generation map available without an NDA.[395] We agree with parties that the ostensible risks described by Public Service are vague and speculative, and that much of the data is already publicly available. While we acknowledge

[388] Hr. Ex. 130, Marion Rebuttal, pp. 13-15.
[389] Hr. Ex. 130, Marion Rebuttal, pp. 24-25.
[390] Hr. Ex. 130, Marion Rebuttal, pp. 15-17.
[391] Hr. Ex. 130, Marion Rebuttal, p. 16, discussing Decision No. C25-0259-I, issued on April 7, 2025, in this Proceeding.
[392] Hr. Ex. 130, Marion Rebuttal, pp. 22-24.
[393] Hr. Tr. August 26, 2025, pp. 185:17-186:3.
[394] Hr. Ex. 130, Marion Rebuttal, pp. 20-21.
[395] Chair Blank dissents, but notes that the Company's existing NDA has several provisions that are commercially unreasonable and would need to be significantly revised consistent with intervenor testimony.

that the Commission is not bound by the actions of commissions in other jurisdictions, we find no evidence on this record that Public Service is different from the myriad utilities described throughout this record as having unredacted maps either completely publicly available on the Company's website, or restricted in much more limited ways, such as username and password requirements, and observe the complete absence of other utilities requiring an NDA to access HCA data.[396] Nor are we persuaded by the Company's invoking of national security incidents (*e.g.*, the events of September 11, 2001;[397] cybersecurity attacks[398]) which we find to be only tangentially related to the question of grid security. We also note that Commission Rule 3541(b) only allows for restriction of access to the utility's web portal only in very specific circumstances. Further, we have rejected the use of NDAs in past decisions. We emphasize the Commission's frustration with the Company's continued unwillingness to facilitate data access. As outlined by IREC and ACE, we specifically find there are advantages of the HCA data being shared widely and find a less onerous NDA could still be counterproductive.

330. Excluding the NDA, we find it appropriate for Public Service to maintain the remainder of its existing authentication process surrounding HCA access. No party opposes the authentication requirement, and some endorse the authentication process, saying that it mitigates the risk of someone using the data to cause harm without hindering access to data for legitimate purposes.[399] We agree that this authentication process can provide risk mitigation without being overly burdensome to potential end users.

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[396] Hr. Ex. 601, Villarreal Answer, pp. 26-30; Hr. Ex. 801, McKerley Answer, pp. 43-44; Hr. Ex. 916, "Hosting Capacity Map Data Disclosure Formats of the Largest 50 US Utilities."

[397] Hr. Tr. September 2, 2025, pp. 317:14–319:3.

[398] Hr. Ex. 130, Marion Rebuttal, pp. 28-29.

[399] IREC SOP at pp. 13-14.

b. Load HCA

331. Like generation data, *tabular* load data is currently available through a secure web portal subject to an NDA; however, load *maps* are only made available in this Proceeding to certain intervenors through the Commission's Highly Confidential data protections and through a platform established by the Company for this specific purpose.[400] There is no publicly available load map, nor any way to access the load map outside of this Proceeding.[401]

(1) Party Positions

332. Parties make similar arguments about the value of load HCA information and the benefits of making it more available to developers, aggregators, and other interested stakeholders. IREC highlights the value of load HCA information to inform customer decisions regarding siting facilities that would increase load and the role this could play in developing EV charging facilities, flexible interconnection, and potentially avoiding certain distribution upgrades.[402] ACE echoes the value of load HCA maps in avoiding upgrades, asserting that Public Service agreed with the potential for this benefit at hearing,[403] and additionally describes public load HCA mapping as a core tool in Governor Polis's Greenhouse Gas Roadmap.[404] AEU also specifically advocates for the publishing of the load HCA map.[405]

(2) Company's Rebuttal Case

333. Public Service emphasizes that load information is particularly sensitive, could be used by bad actors to determine which attacks would be most damaging, and states that the load map "serves up sensitive information on a silver platter." Public Service also warns that overloaded

[400] Hr. Ex. 130, Marion Rebuttal, pp. 9-10.
[401] Hr. Ex. 123, McDermott Rebuttal, p. 34.
[402] Hr. Ex. 800, Mafazy Answer, pp. 10-13; Hr. Ex. 801, McKerley Answer, pp. 10-11.
[403] ACE SOP at p. 16, citing Hr. Tr. August 26, 2025, pp. 255-256.
[404] ACE SOP at pp. 15-16.
[405] AEU SOP at pp. 18-21.

feeders have less redundancy, and load switching becomes less feasible as feeders become more loaded, and so load information could be used to identify the most vulnerable parts of the system. Public Service asks that, if the Commission wants the load map to be published outside of this Proceeding, that the concept should be evaluated "in a thorough and thoughtful manner outside of this proceeding."[406]

(3) Findings and Conclusions

334. We require Public Service to make the load map available without an NDA.[407] As with the generation HCA, we find the Company's security arguments vague and speculative, and agree with parties' arguments about the importance of making the data widely available to stakeholders, especially as the distribution system is evolving.

335. We find it appropriate for Public Service to use its existing authentication process, without an NDA, to make the load HCA map available to interested parties, consistent with the generation HCA data.

3. Cadence of Updates

336. In the 2022 DSP Settlement Agreement, the Company agreed to update HCA data and maps on a quarterly basis, beginning on July 1, 2023.[408] However, since then, the Company has not yet achieved a quarterly cadence. Currently, the maps are updated annually,[409] and data cut off windows can make the maps even more out-of-date than that cadence would suggest. In this Proceeding, it was demonstrated that the hosting capacity analysis available on the Company's

[406] Hr. Ex. 123, McDermott Rebuttal, pp. 36-37.
[407] Chair Blank dissents, but notes that the Company's existing NDA has several provisions that are commercially unreasonable.
[408] R23-0080, Attachment A – Settlement Agreement, ¶ 36.1.
[409] Hr. Ex. 900, White Answer, p. 21.

website, though updated at the end of 2024, was utilizing data from *January* 2024.[410] In this DSP, Public Service indicates that it is targeting quarterly updates in its "short-term (2025)" window, and monthly updates in its "mid-term (2026-2027)" window.[411]

a. Party Positions

337. Overall, parties argue that there is limited value in an HCA that is only updated once per year.

338. IREC recommends that the Company be required to publish monthly map updates by the end of 2026, and in the interim, be required to provide an update in December 2025 using a data cutoff no later than October 2025.[412] IREC posits that HCAs are only useful if grid conditions are accurate, and that out-of-date HCAs could result in submitting applications for areas which no longer have capacity, or deterring applications for areas which have additional capacity due to changes in grid conditions or infrastructure upgrades. IREC particularly emphasizes the importance of more frequent updates of HCAs in a world of changing grid conditions, such as rapid rollout of community solar gardens and net metering applications, and highlights historical concerns about long interconnection timelines and delays. IREC asserts that there is "no minimum" to update frequency for HCAs, that the goal should be real-time updates, which has been achieved by other utilities such as Hawaiian Electric, and that monthly updates are a compromise from that goal.[413]

339. ACE recommends that the Commission require Public Service to start monthly updates by the end of 2026, and publish an updated HCA within 30 days of this Decision, along

[410] IREC SOP at pp. 22-23; ACE SOP at p. 7.
[411] Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, p. 45.
[412] IREC SOP at pp. 23-24.
[413] Hr. Ex. 800, Mafazy Answer, pp. 31-34.

with quarterly updates thereafter through manual processes until automation is achieved. ACE additionally recommends that the Commission state that it will assess civil penalties if Public Service fails to comply with HCA deadlines, and that the Commission should even consider assessing penalties for past non-compliance, such as for missing the deadline of quarterly updates established in the last DSP.[414] ACE warns that outdated maps could result in developers selecting sites that seem to have available capacity but are actually saturated. ACE additionally asserts that ratepayers would also benefit from updated maps, via more efficient use of the grid and Company time and resources.[415]

340. AEU supports the recommendation to update HCAs more frequently and agrees that the Commission should establish a deadline for monthly updates, calling a deadline of late 2026 "reasonable."[416] Tesla agrees that there is limited value in an HCA only updated once per year and likens the process to a "Battleship" type search for capacity if no good information is available.[417]

b. Company's Rebuttal Case

341. Public Service agrees with parties that more rapid updates of HCAs would be beneficial for other stakeholders and also for the Company. It states that more frequent updates would result in fewer and more targeted applications from customers, thus reducing the engineering work needed to evaluate those applications.[418]

342. However, the Company opposes the imposition of a specific deadline for monthly HCA updates. Public Service is focused on implementing the "CYME Gateway" tool, which could

[414] ACE SOP at pp. 17-19.
[415] Hr. Ex. 900, White Answer, pp. 22-23.
[416] AEU SOP at pp. 21-23.
[417] Hr. Ex. 1601, Ehrlich Cross-Answer, pp. 9-10.
[418] Hr. Ex. 124C, Mino Rebuttal, pp. 53-54.

facilitate automation of modeling and speed up HCA updates; however, it is taking the Company longer than expected to implement this CYME Gateway due to the need for coordination with billing and other systems, issues discovered during model validation, and the need for dedicated training and onboarding. With this, as well as additional steps required to automate processes, Public Service asserts that a deadline would not be consistent with the complexity of the project, and that it is important to get the process right rather than discovering issues after it goes live.[419]

c. Findings and Conclusions

343. We require Public Service to publish monthly HCA updates by the end of 2026. We additionally require Public Service to publish an HCA update within 60 days of this Decision, using cutoff data no further back than September 2025, as well as quarterly HCA updates subsequent to that update. It is disappointing that the Company has not only failed to live up to the timeline commitments in the 2022 DSP Settlement Agreement, but has not even articulated here a plan to meet that timeline or deploy the technology to achieve the previously agreed timeline. It is particularly frustrating considering the Commission, the parties, and even the Company, acknowledge how beneficial this data could be in evolving the distribution system and also how insufficient out-of-date HCA data can be. While Public Service has described challenges with the automation process, it is also capable of manually updating the HCA data and has not done so in a way that complies with even the 2022 DSP Settlement Agreement up to this point.

344. At this time, we decline to take ACE's recommendation to consider penalties pursuant to § 40-7-105, C.R.S. The Commission's Rules and Public Utilities Law (*i.e.,* Title 40 of CRS) require penalties to be pursued through specific processes. While we express our dissatisfaction with the infrequency of the Company's HCA updates, we do not find this

[419] Hr. Ex. 124C, Mino Rebuttal, pp. 53-56.

Proceeding to be the appropriate venue to address the assessment of penalties against the Company. However, given these frustrations, as well as the inability of the Company to meet previous commitments, we intend to explore compliance enforcement options if the Company continues to be unable to fulfill its commitments related to HCA data and timelines, especially considering that such a failure continues to jeopardize or slow progress toward some of the very statutory goals at issue in this Proceeding and for which the Company has sought extraordinary cost recovery.

4. Temporal Granularity

345. Hosting capacity can vary throughout the day and the year—daily and seasonal fluctuations in load and generation can naturally affect hosting capacity. Public Service's current load and generation HCAs only look at a single point in time, which represents the daytime maximum loading scenario. However, more granular "time series" HCA analyses can also be conducted, which analyze how much hosting capacity is available during other periods. In its hosting capacity roadmap within the DSP, Public Service targets "8760 analysis" in its "mid-term (2026-2027)" window,[420] which would represent visibility into hosting capacity at every hour of the year.

a. Party Positions

346. IREC points out that 8760-hour analyses, while thorough, can create computational and modeling challenges, and suggests that, once full 8760 data is available, that Public Service publish "576 hour analyses." Under IREC's proposal, a 576-hour analysis would look at 24 hours per month, for both load and generation, which IREC asserts would provide meaningful hosting capacity variation while being more practical and feasible than a full 8760-hour analysis.

[420] Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, p. 45.

IREC asserts that more granular HCA data would be particularly helpful for flexible interconnection, and that projects may be able to interconnect if not looking at the worst-case scenario. To this end, IREC recommends that the Commission require 576-hour analyses be published by the end of 2027.[421]

347. ACE additionally recommends that both 576-hour as well as 8760-hour analyses be published by the end of 2027, agreeing with IREC that these models can enable limited load and generation profiles and be used to facilitate flexible interconnection.[422]

b. Company's Rebuttal Case

348. Public Service disagrees with requiring a deadline for temporal granularity. The Company reiterates that the 8760 analysis is in its HCA roadmap for 2027 and that it has begun studying flexible interconnection but is still working through the logistics of scaling their analyses to the entire distribution system.[423]

c. Findings and Conclusions

349. We require Public Service to publish 576- and 8760- hour results by the end of 2027. Consistent with the cadence of HCA updates, parties have demonstrated the benefits of this analysis, and we believe that establishing a deadline is important for keeping these HCA improvements on track. In particular, more temporally granular results by the end of 2027 would align with the development of flexible interconnection and associated requirements in future DSPs.

5. 15/15 Rule

350. Commission Rule 3033(b) (the "15/15" Rule") states: "At a minimum, a particular aggregation must contain at least fifteen customers; and, within any customer class no single

[421] Hr. Ex. 800, Mafazy Answer, pp. 48-52.
[422] ACE SOP at p. 12.
[423] Hr. Ex. 124, Mino Rebuttal, p. 57-58.

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."

351. Commission Rule 3001(k) defines customer data as "customer-specific data or information … that is:

a. Collected from the electric meter by the utility and stored in its data systems (*e.g.* kWh, kW, voltage, VARs and power factor);

b. combined with customer-specific energy usage information on bills issued to the customer for regulated utility service when not publicly or lawfully available to the general public; or

c. about the customer's participation in regulated utility programs, such as renewable energy, demand-side management, load management, or energy efficiency programs."

352. Public Service excludes feeders that it interprets the "15/15 Rule" applies to from its HCA maps; this removes 180 of the total 809 feeders from the maps.[424]

a. Party Positions

353. Boulder asserts that application of the 15/15 Rule has been extended past its original intent. Boulder claims that inputs to the HCA are not "customer data," and that the 15/15 Rule should not apply to feeder infrastructure, capacity, or loading data sets. According to Boulder, exclusion of feeders creates confusion and obfuscates HCA information for large portions of the distribution system.[425]

354. IREC also asserts that redacting all information from maps, particularly locations of lines, is in violation of the HCA rules. IREC states that the Commission should evaluate each

[424] Boulder SOP at p. 24.
[425] Hr. Ex. 1101, Telischak Answer, pp. 27-30.

data field specifically with regards to whether they could enable disaggregation of customer information. Under IREC's interpretation:

a. Substation name, transformer voltage, and feeder locations are not "customer data," and therefore should be published;
b. Load data *is* customer data, and thusly should be redacted where the 15/15 Rule applies; and
c. Modeled outputs of HCA are a greyer era, and should be published unless the Company can demonstrate, for specific technical criteria, that customer load data can reasonably be disaggregated from the result.[426]

b. Findings and Conclusions

355. We are persuaded by IREC's interpretation of the 15/15 Rule and Commission Rules 3001(c) and (k), 4 CCR 723-3, and therefore adopt IREC's proposed framework for feeder information under the 15/15 Rule. We find the rule should not be read to require redactions of feeders in the Company's HCA maps, except to the extent outlined by IREC to protect customer data. We find such an approach strikes an appropriate balance between customer data protection and enhancing the utility and function of the Company's HCA maps. To the extent there is a dispute regarding a potential need for customer disaggregation, appropriate filings can be made before the Commission.

6. Additional HCA Issues

a. Combining Maps

356. IREC recommends that Public Service be required to publish a single map, which displays both substation and distribution line information for both load and generation. Currently, Public Service's load and generation HCA maps are separate from one another, with the load HCA map only being available in this Proceeding. IREC asserts that combining the maps

[426] IREC SOP at pp. 18-20.

would make for a better user experience, allow for greater visibility into the distribution system, and lead to more efficient use of the HCA.[427]

357. In Rebuttal, the Company indicates that it is "open to suggestions for improvement" of HCA map presentation in the future, but states that for now its concentration is on improving other areas of the HCA, such as developing the automation to update the maps more frequently; it also notes technical challenges with layering and pop-up limitations.[428]

358. We decline to require Public Service to combine maps at this time. We agree with the Company that there are several greater priorities in the development of the HCA. However, we require Public Service to report on the status and potential of combining maps in its next DSP. We additionally encourage Public Service to explore the possibility of combining maps sooner than the next DSP if it is sensible to do so as part of the greater suite of HCA process changes that the Company is required to make.

b. Popup Boxes

359. For both generation and load HCA maps, when an HCA map user clicks on a particular site, the map will bring up a popup box that displays information about the feeder in that location.

360. In Answer Testimony, IREC observes that Public Service's unblurred generation map shows substantially less information in popup boxes than either the blurred map's popup boxes or the tabular data. Discovery conducted in this Proceeding confirms that the unblurred generation map popup box only contains five values, vs. 27 values in the blurred map popup box

[427] Hr. Ex. 800, Mafazy Answer, pp. 26-27.
[428] Hr. Ex. 124, Mino Rebuttal, p. 57.

and 21 values in the tabular data. Similarly, the Company's unblurred load map only contains six values, vs. 20 values in the tabular data.[429]

361. In Rebuttal, Public Service confirms that this discrepancy is in error, that the unblurred boxes should contain all of the fields shown in the blurred boxes and tabular data, and that the Company will make the change.[430] However, IREC points out in its SOP that the Company has not committed to a defined timeline for making the change.[431]

362. We require that Public Service make a filing in this Proceeding within 30 days of this Decision to notify the Commission confirmation that the popup boxes have been fixed or state that they have not been fixed. In any event, we require Public Service to fix the popup boxes by the end of 2026.

c. User Guide

363. In Answer Testimony, IREC recommended that Public Service be required to publish a user guide that explains how to access and navigate HCA maps, download data, and explain all key terms and assumptions contained within the maps.

364. However, during the course of the Proceeding Public Service confirmed that a guide already exists on its public website.

365. In light of this, IREC asks in its SOP for the Commission to ensure that the HCA user guide:

a) Applies to both load and generation HCAs;
b) Explains all terms used in the maps and tabular data;
c) Lists each of the technical criteria and how the relevant thresholds are determined; and

[429] Hr. Ex. 800, Mafazy Answer, pp. 22-24.
[430] Hr. Ex. 124, Mino Rebuttal, p. 59.
[431] IREC SOP at p. 27.

d) Is periodically updated to reflect any changes to the HCA or how the map is displayed.[432]

366. We require that Public Service file in this Proceeding within 30 days of this Decision to confirm that the user guide contains the information requested by IREC or state which information is not included. To the extent that information is missing at the time of that filing date, we require Public Service to update the user guide by the end of 2026.

d. Validation

367. "Validation" is the term used for checking that the HCA's simulation of hosting capacity and limiting criteria actually aligns with real-world conditions. In compliance with the 2022 DSP Settlement Agreement, Public Service validated HCA results for five locations on the grid as part of this DSP. The validation revealed a mismatch in one location, which the Company described as being due to GIS mapping errors, which are updated as they are found;[433] the Company has additional validation in the "long-term (2028+)" window of its hosting capacity roadmap.[434]

368. IREC recommends that the Company be required to submit a detailed HCA validation plan within six months of this Decision, with objectives, a concrete timeline, and an opportunity for stakeholder comment. IREC asserts that validation should be structured, transparent, and repeatable, and provides into the record a "Data Validation for Hosting Capacity Analysis" report it published with NREL.[435] IREC states that it is not aware of any additional HCA validation performed by the Company beyond the five locations described in the DSP. IREC asserts that unvalidated HCAs could lead to inaccurate results, and that users may not be

[432] IREC SOP at pp. 28-29.
[433] Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, pp. 115-116.
[434] Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, p. 45.
[435] Hr. Ex. 800, Mafazy Answer, Att. MM-22.

able to rely on them for siting decisions. It highlights that utilities in Minnesota, Massachusetts, and California have had HCAs with nodes showing little to no hosting capacity available but could, in actuality, support new generation.[436] In Cross-Answer Testimony, AEU witness Turner also supports IREC's proposal for the Company to submit a validation plan.[437]

369. In Rebuttal, Public Service agrees with the importance of validation, and states that it is working on improving its validation process, including by developing python scripts to automate processes. However, the Company disagrees with IREC's specific recommendation on submitting a plan, stating that its focus is on implementing the CYME Gateway tool which will help facilitate automation of the validation processes.[438]

370. We require Public Service to submit a validation plan within six months of this Decision, as recommended by IREC. We agree with the importance of validating the HCAs outlined by both Public Service and IREC. While Public Service's focus is on automation of the HCA process, it should be able to provide timeline information for additional validation in the context of the related HCA timelines established in this Decision.

e. Downloadable Data

371. IREC recommends that the Commission order Public Service to include download links in the popup boxes, which would produce a .csv file with all of the basic grid data on that line, such as technical criteria and hosting capacity values. IREC notes that users are able to download load and generation tabular data from the restricted section of the web portal, but not from the maps themselves. IREC argues that popup boxes may not be large enough to contain all

[436] Hr. Ex. 800, Mafazy Answer, pp. 52-55.
[437] Hr. Ex. 2102, Turner Cross-Answer, p. 26.
[438] Hr. Ex. 124, Mino Rebuttal, p. 58.

the data that developers would and that downloadable data would make for more efficient use of the HCA.[439]

372. Consistent with IREC's recommendation, we require Public Service to allow for data to be downloaded from the popup boxes by the end of 2026.

f. Nodal Results and Limiting Criteria

373. IREC recommends that the Company publish nodal results for both its load and generation HCAs. Nodes refer to sectionalizing devices, such as voltage regulators or capacitors, that divide feeders into line sections which may have varying levels of hosting capacity. IREC quotes Public Service as saying in discovery that nodal analysis is "essential for identifying localized system constraints and for producing maps that offer enhanced informational value across all scenarios;" however, while the Company produces this data for internal purposes, both the blurred and unblurred generation map, as well as the generation and load tabular data, only provide ranges for whole feeders rather than specific nodal data. The load map provided in this Proceeding does display nodal results, but as discussed elsewhere, has not been previously made publicly available in any capacity. IREC points out the relative lack of usefulness of feeder-level data, noting that over 80 percent of the feeders in the generation tabular data show "between 0 MW and 10 MW." IREC contrasts this with an example from National Grid's HCA map, where a feeder level map shows hosting capacity value in excess of 5 MW for a particular feeder, but certain segments within that feeder have capacity as little at 0.29 MW. Finally, IREC points out that Xcel Energy does publish nodal generation results in its Minnesota operating company.[440]

[439] Hr. Ex. 800, Mafazy Answer, pp. 25-26.
[440] Hr. Ex. 800, Mafazy Answer, pp. 37-42.

374. IREC also recommends that, when publishing nodal results for its HCAs, the Company should also provide comprehensive limiting criteria information for each node. Behind the single Hosting Capacity number, HCAs provide information on the constraints on hosting capacity, known as "limiting criteria;" these limiting criteria can be classified into voltage, thermal, and protection categories. IREC asserts that *all* limiting criteria should be published, not just the single most limiting constraint, giving an example that a voltage constraint could be addressed with smart inverter settings, but a thermal constraint on top of that could be more expensive and time consuming for a developer. IREC notes that the HCA model developed by the Company does produce limiting criteria, but does not publish them on either the unblurred generation map or the load map, and even on the blurred generation map they are only shown at the feeder level, which is not as useful as nodal level data would be.[441]

375. In Rebuttal, Public Service indicates that it is "amenable to evaluating the feasibility" of incorporating some nodal data into popup boxes for the generation HCA map. However, the Company warns that providing nodal information could also increase visibility into system vulnerabilities, and emphasizes concerns about that information becoming available to bad actors.[442]

376. We require Public Service to publish results for its load and generation HCAs at the nodal level, along with the limiting criteria information for each load, behind the secure web portal but without the restriction of an NDA, consistent with the recommendations of IREC. As with the generation and load HCAs themselves, we agree that the value of this information is substantial, and we find the Company's security arguments to be vague and speculative.

[441] Hr. Ex. 800, Mafazy Answer, pp. 43-48.
[442] Hr. Ex. 123, McDermott Rebuttal, pp. 37-38.

g. Distribution Lines / Substation Locations

377. At this time, substation locations are not included on HCA maps at all. Distribution line locations are published on the unblurred generation map and load map, but not on the blurred map or in the tabular data. IREC recommends that the Commission order Public Service to make distribution lines and substation locations available without an NDA. In IREC's testimony, as an example of the usefulness of distribution line information, IREC shows a public map from Southern California Edison's service territory, which shows circuits that would support generation on one side of a shopping mall but not the other; IREC argues that it would not be possible to analyze project options to this level of details with blurred locations of lines. Regarding substations, IREC argues that proximity to substations can indicate that more capacity is available because of less voltage drop, and can influence reconductoring costs as well.[443]

378. Given the security changes discussed elsewhere in this Decision, we find there is no change needed to the distribution line presentation in Public Service's HCA maps. Now that the NDA will be eliminated, only presenting the specific distribution line information on the unblurred map behind the secure web portal is reasonable. However, as substation information is currently not included on any of the HCA maps, going forward we require Public Service to include substation locations on the unblurred maps behind the secure web portal. We agree with IREC that this information is valuable and thus order the Company to make it available.

[443] Hr. Ex. 800, Mafazy Answer, pp. 17-22.

7. AVPP Feeders List

379. The AVPP settlement notes that "the terms of access to geospatial data regarding feeders eligible for the distribution compensation remains in dispute and may be further litigated."[444]

380. Public Service posits that the list of AVPP feeders is highly sensitive data, which would be disclosed through the secure web portal and would require the signing of the same NDA currently required to access the HCA maps.[445]

381. ACE asserts that the feeder list should be public. ACE argues that designating the feeders as confidential would prevent aggregators from recruiting customers located on those feeders, and that the Company has failed to demonstrate why the feeder list requires confidential treatment. ACE says the Company has not provided any written justification for the disclosure being harmful, in contrast to its arguments on the HCA maps.[446]

382. AEU also recommends the Company provide the list of eligible feeders publicly. AEU notes that SB 24-218 requires "streamlined and reasonable data requirements for participation," and asserts that the nonstandard NDA does not align with this. AEU argues that making the feeder list public is crucial for the success of the AVPP program, that customers would be unable to understand if their property is on a feeder eligible for compensation under this arrangement, and that the Company has not justified the confidentiality of the list.[447]

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[444] Hr. Ex. 131, VPP Settlement, ¶ 23.
[445] Hr. Tr. August 26, 2025, pp. 214-215.
[446] ACE SOP at p. 30.
[447] AEU SOP at pp. 16-18.

383. We find that the AVPP feeder list should be made public. We agree with parties that it is important for AVPP program participants to share this information with eligible customers and we observe the lack of support for keeping the list behind an NDA.

I. Other Issues

1. Green Button Connect

384. Green Button Connect ("GBC") is a standard for data sharing across the utility industry, accessible via a variety of software applications. The Company's GBC platform was designed by Franklin Energy, and the Company's implementation of GBC has been certified by the Green Button Alliance ("GBA").[448] The Commission originally approved the Company's GBC offering in 2017.[449]

a. Party Positions

385. Mission:data asserts that the Company's GBC implementation is full of errors, limitations, and is not in line with expectations for functionality or Commission directives. As part of Mission:data's analysis, Mission:data witness Michael Murray registered as a GBC third party to receive customer data and encountered several challenges which are outlined in his testimony. Murray identifies six expectations for the operation of a GBC platform; in his analysis, Murray assesses Public Service's performance on ease of onboarding, user-friendliness, standards compliance, accuracy and completeness, and documentation. He asserts that the sixth expectation, timeliness of data delivery, has not been assessed because of his inability to receive automated customer data.[450]

[448] Hr. Ex. 129, Pascucci Rebuttal, pp. 13-14.
[449] *See* Decision No. C27-0556 at ¶ 38, issued in Proceeding No. 16A09588E on July 25, 2017.
[450] Hr. Ex. 1500, Murray Answer, pp. 17-20.

386. Regarding onboarding, Murray details the timeline of his efforts to register as a GBC data recipient with Public Service. Murray first attempted to register on March 5, 2025, and received an error message; although Murray was eventually manually registered using a PDF form, Murray received additional error messages when attempting to authorize customers, and as of June 23rd, was still unable to make automated requests for customer-authorized information. Murray asserts that Public Service does not meet expectations for onboarding and suspects that minimal GBC testing was conducted prior to release.[451]

387. Regarding user-friendliness, Murray asserts that the Company's GBC implementation is "not ready for prime time." Using a "Green Button Scorecard" ranking methodology developed by Mission:data, Public Service's GBC implementation was scored at a 1.7 out of 5. Murray notes that the authorization request URLs do not work correctly, and that the method to manually grant authorization is long, cumbersome, and requires a number of steps. He also notes that even the manual method may result in error messages. Other problems identified by Murray include a confusing authorization user interface, with display glitches and names of third parties obscured, and the need for customers with more than one "billing account" to make multiple discrete authorizations.[452]

388. Regarding standards compliance, while Public Service's GBC implementation is certified by the GBA, which indicates it passed numerous technical tests and is interoperable with multiple third-party applications, Murray notes that the certificate record is over 18 months old and calls it an inaccurate representation of the Company's current GBC system; Murray asserts that there is "no way" the current implementation would pass the tests, particularly tests around

[451] Hr. Ex. 1500, Murray Answer, pp. 20-30.
[452] Hr. Ex. 1500, Murray Answer, pp. 30-47.

authorization and authentication. Murray speculates there could have been changes to the GBC system since the certificate was established, that the certification process could have been conducted in a test environment rather than the actual production system, or that the testing process was not rigorous or controlled.[453]

389. Regarding accuracy and completeness, Murray asserts that a wealth of information is missing in Public Service's GBC implementation and that the implementation fails to meet a reasonable standard for "parity of access," as the Commission emphasized in C24-0815. Murray identified the following gaps in completeness:

a) *Gas usage or costs*: Although a Public Service witness in Proceeding No. 23A-0471E testified "customers have the option to share usage data from their electric *and* gas meters through Green Button Connect," in this Proceeding, Company witness Pollock indicated in discovery that gas-only customers are not able to use GBC "because the Company does not have gas AMI." Mission:data asserts that GBC works with monthly or daily intervals, and so advanced metering is not truly required for GBC implementation.[454] [455]

b) *Rate information*: Murray states that rate data is needed for many cost-saving and load-shifting strategies, such as optimizing the usage of an EV on time-of-use rates compared to flat rates. He warns that algorithms for those sorts of strategies could be useless or even potentially harmful if rate changes do not come across in the system; *i.e.*, if the time-of-use peak window changes. Murray also notes that the GBC platform can handle rate data, and large investor-owned-utilities in California do provide that information. [456]

c) *Customer account information*, such as addresses and account numbers, does not come across in GBC. Murray notes that the GBC standard has a separate file for personally-identifiable information, and that this information is useful for tracking customers during program enrollments, tracking multi-site commercial customers, and preventing "dual participation" in multiple VPPs. [457]

d) *"High quality" usage data*: Public Service provides raw usage data through GBC, but according to Murray, does not provide the "cleaned" post-validating/editing/estimating data which is ultimately used for billing.

[453] Hr. Ex. 1500, Murray Answer, pp. 47-52.
[454] Hr. Ex. 1500, Murray Answer, pp. 53:1-55:8.
[455] *See* "Penalty Motion" Section below for additional information on this issue.
[456] Hr. Ex. 1500, Murray Answer, pp. 55-60.
[457] Hr. Ex. 1500, Murray Answer, pp. 61-62.

Murray states that this could negatively impact customers, because of errors or erroneously high values that could lead to misinformed decision making, and warns that VPP aggregators could have similar issues. [458]

e) Additionally, Murray recommends that Public Service be required to provide at least two years of historical usage data, or, if a customer has been on the system for fewer than two years, data back to the date they became a customer. While AMI meters are relatively new on the system, Murray notes that monthly usage data can be shared through GBC as well, and so at least two years' worth of data should be available.[459]

390. Regarding documentation, Murray lists many advantages of good documentation, including reducing technical support burden, reducing barriers for third parties looking to become authorized, tracking any deviations from the GBC standard, as those deviations would be more likely to be undocumented elsewhere. However, Public Service only provides one document on use of its GBC system, which Murray describes as sparse, containing incorrect information, and not being provided until after registration.[460]

391. In the context of its criticisms of GBC implementation, Murray claims that Public Service is not in compliance with rule 3207(d). He particularly highlights the absence of "high-quality" usage data, asserting that raw usage data is necessarily incomplete and does not fit the definition of "standard customer data" as it is not the data actually maintained on its systems and used in the ordinary course of business. Murray notes that, in Proceeding No. 14R-0394EG, the Commission rejected proposals to narrow the definition of "standard customer data," and also notes that several other utilities provide "billing quality" usage data through GBC in place of or addition to raw data. Murray also highlights contradictory information on whether GBC is limited

[458] Hr. Ex. 1500, Murray Answer, pp. 62-69.
[459] Hr. Ex. 1500, Murray Answer, pp. 46-47.
[460] Hr. Ex. 1500, Murray Answer, pp. 69-71.

to residential customers, but asserts that exclusion of customer types, to the extent it is occurring, would be arbitrary and that no customer classes are exempted from rule 3027(d).[461]

392. Murray also claims that Public Service does not satisfy the Commission's concerns about data parity established in Decision No. C24-0815, saying that data parity is not achieved with Public Service's GBC implementation for quality of usage data, applicable rates, account information, or natural gas usage data. Murray speculates that data parity issues could cause trouble for VPP aggregator registration and prevent VPP aggregators from seeing the information that forms the basis of their payments.[462]

393. Murray additionally criticizes Public Service's implementation of its Home Area Network service, as well as My Energy Connection, the mobile app that allows customers to access Home Area Network functionality. Mission:data asserts that the My Energy Connection app has several bugs, including missing real-time energy usage data, "stuck" data that does not update, and reports of "temporary outages" that last for an extended time, and also notes the app's poor ratings on app stores.[463] Mission:data also points out that Home Area Network functionality is limited to "customers with one premise, one account, and one meter," which Mission:data asserts is a policy never approved by the Commission and could result in frustrated customers.[464]

394. AEU supports Mission:data's concerns regarding GBC. AEU witness Turner emphasizes the importance of customer data for AVPP implementation, including rate class information (to verify that the customer is in a distribution-level class in the first place) and energy usage information (to size a system and assess a customer's performance). AEU emphasizes "the

[461] Hr. Ex. 1500, Murray Answer, pp. 71-78.
[462] Hr. Ex. 1500, Murray Answer, pp. 78-80.
[463] Hr. Ex. 1500, Murray Answer, pp. 88-92.
[464] Hr. Ex. 1500, Murray Answer, pp. 81-87.

urgency of the issue," and notes that Company has had "almost ten years" to improve its GBC system and the need for aggregators to have access to usage data.[465]

395. Mission:data recommends that, if Public Service does not accomplish all of its recommended changes within six months of this Decision, then Public Service should be required to procure a new GBC platform through an RFP process.

396. AEU recommends requiring the Company to present a detailed plan, with timelines and benchmarks, to fix its GBC program within six months of this Decision, or, if the plan is insufficient or the Company misses the milestones, to issue an RFP for a new GBC implementor.

b. Company's Rebuttal Case

397. Public Service witness Michael Pascucci asserts that the Company's existing GBC implementation is functional and adequate and describes Mission:data as "letting the perfect be the enemy of the good." Pascucci counters several of the criticisms in Murray's testimony and notes that the Commission has affirmed the Company's approach to data access in the past. Pascucci notes that the Company worked with Franklin Energy to design, build and test its GBC platform, which has been certified and has been used by 27 customer-authorized third-party service providers; he also highlights that seven active vendors have successfully utilized the Company's GBC implementation, with technical issues being limited and successfully resolved along the way.[466]

398. With regards to user experience errors, Pascucci notes that Murray was "attempting to utilize GBC as both a vendor and a customer at the same time," which causes issues; that Murray does not actually have an Xcel customer account; and that once Murray began receiving data from

[465] Hr. Ex. 2102, Turner Cross-Answer, pp. 27-30.
[466] Hr. Ex. 129, Pascucci Rebuttal, pp. 13-14; 17-21.

Xcel customers he no longer encountered connection issues. Pascucci also points out that Murray eventually stopped responding to contact from Public Service or reaching out on technical problems, which Pascucci suspects shows that Murray's intention was to discover problems.[467]

399. With regards to gas meter data, Pascucci asserts that Murray's criticisms are outside of the scope of this Proceeding, as gas data does not relate to the electric distribution system, distribution infrastructure, or services such as VPPs, and would be better explored in a demand-side management proceeding. Pascucci also notes that, since the Company does not have AMI meters for gas at this time, the value of gas data in GBC would be limited. Nonetheless, Pascucci does state that Public Service is exploring whether gas billing data could be provided via GBC.[468]

400. The Company refutes Murray's claims that it does not provide "high quality" usage data. Public Service witness Zachary Pollock testifies that the Company *does* provide "processed data" after the validation process is conducted. Although the process of validating the data takes time ("generally … within 24 hours"), the validated information ultimately replaces the raw data in GBC; thus, according to the Company, there is no data disparity.[469] Pollock additionally notes that, in response to Murray's answer testimony, the Company did an analysis to compare raw data and processed data, and found that "less than 1 percent of raw interval date was updated" through the validation process, and that inaccuracies in raw data could hypothetically overstate performance in addition to understating performance.[470] Nonetheless, while maintaining that the data is accurate, Pollock does say that the Company is exploring additional transparency regarding data quality.[471] As an alternative, Company witness Pascucci says that the Company could wait to

[467] Hr. Ex. 129, Pascucci Rebuttal, pp. 14-15; 18.
[468] Hr. Ex. 129, Pascucci Rebuttal, p. 22.
[469] Hr. Ex. 122, Pollock Rebuttal, p. 99; Hr. Ex. 122, Attachment ZDP-10.
[470] Hr. Ex. 122, Pollock Rebuttal, pp. 100-101.
[471] Hr. Ex. 122, Pollock Rebuttal, p. 101.

make any data at all available until the processing work is completed, but it would not be available as quickly as the raw data.[472]

401. With regard to Home Area Network restrictions, Pascucci asserts that expanding Home Area Network to customers with more than one meter would not be cost effective, would be used only by a "tiny minority" of customers; Pascucci also asserts that the Company is not out of compliance with any Home Area Network requirements and the existing functionality is reasonable and prudent.[473]

c. Discussion, Findings, and Conclusions regarding GBC Improvements

402. Mission:data recommends that, if Public Service does not accomplish all of its recommended changes within six months of this Decision, then Public Service should be required to procure a new GBC platform through an RFP process.

403. AEU recommends requiring the Company to present a detailed plan, with timelines and benchmarks, to fix its GBC program within six months of this Decision, or, if the plan is insufficient or the Company misses the milestones, to issue an RFP for a new GBC implementor.

404. We find the management of customer data to be an essential element of several programs that try and make the most efficient possible use of the distribution grid and resources, and appreciate Mission:data's recommendations for improvement in this space, especially as several of the issues identified by Mission:data seem straightforward and obvious for the Company to address. To this end, we require Public Service to create a detailed plan to improve its GBC implementation. The report should be filed within six months of this Decision, and should include timelines for:

[472] Hr. Ex. 129, Pascucci Rebuttal, pp. 21-22.
[473] Hr. Ex. 129, Pascucci Rebuttal, pp. 23-24.

a. Providing gas usage data through GBC;
b. Historical usage data for at least 24 months through GBC;
c. Revised presentation of "raw data" and "billing quality" data, providing both fields if possible;
d. Bug fixes for GBC as well as the My Energy Connection app; and
e. Information on the feasibility and cost of expanding Home Area Network functionality to customers with more than one property, account, or meter.

(1) Restrictions on Data Sharing

405. Public Service's implementation of GBC allows customers to choose how long they authorize sharing their data, but has a maximum time period of two years beyond the data of authorization, after which customers must reauthorize third-party access. Mission:data argues that this limit creates unnecessary disruptions, confusion and hassle for customers, and is inconsistent with the data consent sharing form approved by the Commission in 14R-0394EG, which amended the electric and gas rules regarding privacy and data access.[474]

406. In Rebuttal, Public Service asserts that the two-year limit is a "necessary" default safety feature, and ensures that customers maintain awareness that they are sharing data.[475]

407. We require Public Service to eliminate its two-year restriction on data sharing through GBC; however, we additionally require Public Service to develop an annual data sharing notification accompanied by a simple withdrawal option. We agree with Mission:data that automatically ending customer connection could lead to disruptions, but additionally find that it is important to provide reasonable, routine notice and options to customers so that customers may maintain control over their data.

(2) Authorization URL

408. As discussed above, GBC authorization is currently conducted through a manual process, involving a series of links on Public Service's website.

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[474] Mission:data SOP at pp. 12-13.
[475] Hr. Ex. 129, Pascucci Rebuttal, p. 16.

409. Mission:data witness Murray claims that in absence of a functional authorization URL, Public Service's GBC authorization process is "labyrinthine," confusing, requires a number of steps, and can still result in error messages. Mission:data asserts that a simple authorization URL is necessary to scale data sharing to support the VPP rollout.[476]

410. In Rebuttal, Public Service posits that the ability to authorize via URL is not a required element of GBC certification, and that several of Murray's error messages using its manual authorization process were a result of not having an Xcel Energy account and not being an Xcel Energy customer. However, Public Service does recognize that an authorization URL could be a useful feature for its GBC interface and is exploring the potential to implement it.[477]

411. We require Public Service to include the development of a functional authorization URL in the six-month process described above. While it is possible that some of the use cases described in this Proceeding were atypical and had unique challenges, Public Service and other parties agree that a simple authorization URL would be useful functionality to provide, and is important as part of the continued rollout of new programs.

(3) Recertification

412. As noted above, Mission:data asserts that Public Service would not pass the GBC certification test if it was retested today, due to the absence of a working authorization URL. Mission:data notes that the domain name of the server listed on Public Service's GBC certification says "staging," indicating that the certification was not done on the actual production server. Accordingly, Mission:data recommends the Commission require Public Service to recertify its GBC system using the "production" server that customers access when they try to share data.[478]

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[476] Mission:data SOP at pp. 9-11.
[477] Hr. Ex. 129, Pascucci Rebuttal, p. 16.
[478] Mission:data SOP at pp. 11-12.

413. In Rebuttal, Public Service asserts that it has not made any changes to its GBC implementation that would trigger a recertification requirement since it was originally certified with the GBA and that 27 third-party service providers have been approved access up to this point, along with seven active vendors, with technical issues largely being limited and successfully resolved along the way.[479]

414. We deny Mission:data's recommendation to require recertification at this time. Mission:data has not provided any specific evidence that the situation with Public Service's GBC implementation has changed since it was certified, and we have set an expectation for the implementation of a working authorization URL, which is Mission:data's largest contention regarding recertification. However, depending on the results of the GBC improvements being required, this recommendation could be revisited in future proceedings.

(4) "Standard Customer Data" terminology

415. Mission:data argues that the Company's GBC system does not conform with the requirements of Commission Rule 3027(d) which requires the Company to provide access to a customer's "standard customer data" in electronic machine-readable form to the customer or any third-party recipient authorized by the customer.[480] Mission:data asserts Public Service inappropriately does not provide access through Green Button Connect to all standard customer data that the customers' authorized third parties, particularly VPP aggregators, need to provide analysis and insights to customers about their energy usage. Mission:data recommends the Commission deem any customer data in the possession of Public Service that the Company

[479] Hr. Ex. 129, Pascucci Rebuttal, pp. 12-14.
[480] Mission:data SOP at p. 17.

requires for registration, enrollment, or settlement of VPPs to be information that must be provided pursuant to Rule 3027(d).[481]

416. Mission:data specifically highlights two demonstrative types of VPP-related standard customer data that Public Service fails to provide: (1) the customer's applicable rate and (2) customer program enrollment. First, Mission:data explains Public Service does not provide information through GBC about which rate schedule applies to a specific customer, which Mission:data states is critical for a third party to be able to model potential bill savings that customers may enjoy as a result of installing a heat pump or a battery. Mission:data maintains a customer and their authorized third party should not be required to rely on the customer's memory or a copy of their bill to determine their applicable rate. Mission:data asserts this information is "standard customer data" under rule 3027(d) and Rule 3001(kk) which defines standard customer data as "customer data maintained by a utility in its systems in the ordinary course of business."[482] According to Mission:data this information is maintained in Public Service's ordinary course of business because a customer's applicable rate appears on their bill.

417. Mission:data then explains Public Service also does not provide information about whether a customer is currently participating in a load management program, even though the GBC standard allows a utility to provide this information. Mission:data asserts this omission creates challenges for VPP aggregators, which must affirm that the customers they enroll in their VPPs are not already participating in another load management program. Mission:data highlights testimony from Company Witness Pascucci in which he agreed that if the Commission clarifies that customer program participation information is "standard customer data," then Public Service

[481] Mission:data SOP at p. 19.
[482] Mission:data SOP at pp. 5-6.

would provide that information through GBC. Mission:data also notes that Commission Rule 3001(j)(III) defines "customer data" as including, among other types of data, information "about the customer's participation in regulated utility programs, such as … load management or energy efficiency programs." Mission:data asserts it is necessary for the Commission to deem this information to be "standard customer data" to ensure fairness and data parity between Public Service and third parties such as VPP aggregators.

418. We agree with Mission:data's interpretation of the Commission's rules governing the provision of standard customer data in electronic form in this context and find the information highlighted by Mission:data, which appears to be kept in the Company's ordinary course of business, to be "standard customer data" that the Company must provide through GBC.

(5) GBC Tariff

419. Mission:data recommends that the Commission direct Public Service to file a tariff governing its GBC system. Mission:data asserts that the terms of use governing GBC have not been reviewed or approved by the Commission, are unfair, and undermine VPP aggregators. Mission:data asserts that a potential tariff could serve as a "single source of truth" for functionality and standards for the Company's GBC implementation.[483]

420. We decline to adopt a GBC tariff at this time. We note that formalizing GBC standards as a tariff could require a substantial effort to implement and maintain, with each change requiring an advice letter filing, and that the near-term improvements outlined in this Decision make for a higher priority. However, we find that a tariff, or another document which outlines GBC, could be a useful development to explore in future proceedings.

[483] Mission:data SOP at pp. 19-20.

(6) Independent Consultant

421. In addition to its improvement recommendations, Mission:data further asserts that continuous testing and improvement are critical for both GBC and the Home Area Network. To that end, Mission:data recommends that the Commission direct Public Service to hire an independent consultant to prepare periodic reports on a random sample of customers' experiences with sharing their data via GBC and the Home Area Network. Under Mission:data's proposal, the report would be filed in this Proceeding as a compliance filing every six months; the report would show the results, time elapsed, problems witnessed, interview summaries, and actions taken to mitigate issues, as well as the overall rating and reviews of the My Energy Connection mobile application to connect Home Area Network devices. Additionally, Mission:data recommends that, for any customer tested that is unable to access, use or share their data in this report, the Commission should assess a penalty on Public Service based on the number of customers affected by the violation, calculated by extrapolating the sample size to the total number of customers by class.

422. We decline to adopt Mission:data's recommendation for an independent consultant at this time. As with the tariff discussion above, we recognize that there are several near-term improvements that Public Service is required to undertake, but we do have interest in developing feedback mechanisms if the Company does not show improvement with its GBC implementation

2. Penalty Motion

423. On July 28, 2025, Mission:data filed the Penalty Motion in this Proceeding, moving for the Commission to impose a penalty on the Company for making "false and misleading statements" in sworn testimony. Mission:data claims that a Public Service witness made a false statement in Proceeding No. 23A-0471E (the "SDK Proceeding"), and it only found out that

statement was incorrect in this Proceeding through discovery. Mission:data claims that in discovery, Company witness Murray stated in the SDK Proceeding that "[c]ustomers have the option to share usage data from their electric and gas meters through Green Button Connect." However, Mission:data asserts that Company witness Pollock in this Proceeding stated that the gas-only customer cannot use Green Button Connect because "the Company does not have gas AMI."[484]

424. Mission:data claims that the incorrect statement by Public Service is grounds for a financial penalty because the statement is a violation of the Commission's rules that all written testimony include a signed affidavit attesting to its truthfulness. Mission:data claims it was harmed by the misstatement, and that the penalty should be in an amount determined by the Commission, but counting the days since the false statement and multiplying it by the $20,000 per day penalty in § 40-7-105(1), C.R.S., results in a $9,440,000. Mission:data asserts that the Commission has the ability to order penalties pursuant to § 40-7-105(1), C.R.S., and that Public Service violated at a minimum, Commission Rule 1202(f)(VIII), 4 CCR 723-1 and CRE 603, which is incorporated into the Commission's rules by Rule 1501(a), 4 CCR 723-1.

425. Mission:data argues the Commission should not reopen the SDK Proceeding, but instead address the matter in this Proceeding because the Commission's order in the SDK Proceeding requires the Company to address data access and sharing practices in the DSP, and because the discovery response in the DSP Proceeding is how Mission:data realized that the SDK Proceeding testimony was incorrect. Mission:data also requests that the Commission award Mission:data attorney and consulting fees for time spent addressing this issue.

[484] Motion for Penalty at p. 3 (quoting Attachment C, Public Service Response to Mission:data 4-3(b), dated May 30, 2025.)

426. In response, to Mission:data's Motion for Penalty, Public Service admits that witness Miller's testimony was "mistaken;" however, it asserts that it was not an intentional misstatement.[485] Public Service states that the misstatement came to light in the DSP proceeding, and that within the DSP Proceeding the Company accurately explained that Green Button Connect is not used to share natural gas usage data. Public Service argues that the misstatement in the SDK Proceeding is not a significant or material issue in the SDK Proceeding and notes that the ALJ's decision in the SDK Proceeding did not discuss Green Button Connect. Public Service also contends that there is no support for the contention that Public Service witness Miller either knew his statement was false or was not qualified to be a witness and that the statement did not cause substantial prejudice to Mission:data in either the SDK Proceeding or in this Proceeding.

427. Public Service argues that the Motion should be denied on procedural grounds. The Company asserts Mission:data's motion is procedurally improper because only the Commission's trial staff may pursue civil penalties against public utilities under §§ 40-7-113.5 and 40-7-116.5, C.R.S. Public Service asserts these statutes and Commission Rule 3010, not § 40-7-105(1), govern the Commission's processes for assessing civil penalties. Public Service emphasizes that under the relevant statutory scheme civil penalties may only be brought against public utilities by the Commission's trial staff in a CPAN proceeding. Public Service therefore asserts that, by filing its motion in this Proceeding, Mission:data is improperly attempting to usurp the role of the Commission's trial staff in enforcing alleged violations. The Company next contends Mission:data's motion ignores the substantive and procedural requirements of §§ 40-7-113.5 and 40-7-116.5, C.R.S. and Commission Rule 3010 and improperly relies entirely on § 40-7-105, C.R.S. Public Service describes § 40-7-105 as a general, historical statute that

[485] Public Service Response at p. 8.

initially recognized the Commission's authority to seek civil penalties, provided the Attorney General or a district attorney file suit in a district court with proper venue. Finally, Public Service asserts its due process rights would be denied if the Commission adjudicated Mission:data's motion within this Proceeding. Specifically, the Company asserts several possible due process violations including a lack of notice by the Commission's trial staff of the alleged intentional violations, no specificity of the applicable Colorado statutes or Commission rules or orders allegedly violated, no valid assertion of the correct amount of civil penalties sought, no opportunity for Public Service to file an answer to the notice of civil penalty assessment, and no meaningful opportunity for a fair hearing on the allegations of intentional violation.

428. We deny the Penalty Motion filed by Mission:data. The Penalty Motion is not properly before us within this adjudication. We find the Commission does not have authority to issue a penalty in the process Mission:data suggests pursuant to § 40-7-105, C.R.S., and the motion does not afford Public Service sufficient due process.

429. While we decline to address the merits of the Penalty Motion, we do caution that all parties appearing before the Commission, but particularly regulated utilities, should provide accurate and trustworthy testimony at all times. By all appearances, the statement made by a Public Service witness in the SDK Proceeding is a false statement. Oversights such as this on easily verifiable facts are inexcusable and degrade trust. However, when false or misleading statements are made within a proceeding, the Commission is not without recourse. The Commission can, if brought to our attention in a timely manner, take many approaches to correcting the record, such as striking testimony, making referrals to the bar, excluding witnesses, or reopening if based on improper testimony. All such options can be considered when false or misleading testimony is discovered within an adjudication. However, after an adjudicated

proceeding is closed, considerations of due process and the Commission's statutory civil penalty framework prevent the Commission from addressing a motion seeking the imposition of penalties within a separate and ongoing adjudication. Such a motion presents notice and record concerns and neglects the processes laid out in statute and Commission rules. While we are troubled by the potentially false or misleading statements raised in Mission:data's motion, we find that the motion is procedurally improper and is therefore denied.

3. Security Architecture

430. In Proceeding No. 23A-0471E, the Commission approved a settlement agreement which approved Public Service's data delivery study, as well as the continued use of the Company's current pathway to provide data to customers and third parties. However, the Commission additionally directed the Company to address in this DSP proceeding whether an alternative security architecture could be developed to make Direct Data Upload ("DDU") feasible.[486]

431. In the Filing of Additional Information in this Proceeding, Public Service indicates that it conferred with Itron, which maintains that a single, shared agent would result in security compromises which make doing so an unacceptable risk. However, the filing also discusses a potential cloud solution, which the Company asserts would provide the same information as a DDU without compromising the meter security. Public Service also reiterates that the Company will continue evaluating costs and benefits of alternative data delivery options, as memorialized in the settlement agreement in 23A-0471E.[487]

[486] Decision No. C24-0815 at ¶ 48.
[487] Hr. Ex. 109, Filing of Additional Information, pp. 32-37.

432. Mission:data asserts that the Filing of Additional Information was insufficient and did not truly consider an alternative architecture, and instead proposes that Itron should not serve as the exclusive digital signatory of security certificates for customer-authorized recipients of DDU, with other service providers potentially allowing for one-way authentication, rather than the mutual authentication required by Itron currently. As another alternative to this, Mission:data recommends that the Commission disclaim regulatory supervision of the meter-based app store, which is the list of software products Itron authorizes to receive data from the Company's Itron meters. Doing so, according to Mission:data, would "remove any potential shield of immunity against the nation's antitrust laws."[488]

433. In Rebuttal, Public Service reiterates that it was approved to utilize the Itron meters in Proceeding No. 23A-0471E, that DDU is not feasible for security reasons, and that modifications to the existing agreement with Itron could result in substantial liability increases for both the Company as well as its customers. Public Service also reiterates that other options, such as cloud-based solutions, should continue being explored.[489]

434. We deny Mission:data's recommendation to modify the current security architecture surrounding Public Service's meters. We note that the settlement approving Public Service's current approach was approved in 23A-0471E, that the Company's filing of additional information provided additional details on the feasibility of alternative architecture as required, and that the security concerns outlined by Public Service seem well-founded. However, we require Public Service to further discuss the feasibility, costs, and benefits of the alternative

[488] Mission:data SOP at pp. 25-28.
[489] Hr. Ex. 129, Pascucci Rebuttal, pp. 27-30.

cloud-based solution discussed in its Filing of Additional Information and Rebuttal Testimony in the six month process described above.

4. VPP Aggregator Agreement

435. Section 8 of the VPP aggregator agreement filed in this Proceeding reads: "Prior to receiving any customer data from Company … the Aggregator shall obtain and provide the Company with written consent and approval from each Aggregator customer to receive Customer Data from Company. As a condition … the Aggregator shall not use or process the Customer Data for any purpose that is unlawful or prohibited or for any use or purpose beyond the authorization and consent provided to Aggregator by the relevant customer. **Such use and processing (along with the corresponding customer authorization and consent) must be limited to only that which is necessary to fulfill the requirements of the Virtual Power Plant.**"[490] (emphasis added).

436. Mission:data recommends that this sentence be stricken from the VPP aggregator agreement. Mission:data expresses concerns that this language would prevent an aggregator from using customer data for other purposes, such as electrification modeling or energy efficiency advising, even if the customer agrees to them doing so. Another instance postulated by Mission:data is the aggregator asking a customer if they would like a cost-benefit analysis of replacing their furnace with a heat pump. Mission:data asserts that customers have a right to share their usage for legitimate purposes, and that this right would be undermined by the proposed agreement.[491]

437. We reject Mission:data's proposal to strike this sentence from the VPP aggregator agreement. However, we instead require the sentence be modified through a stakeholder process,

[490] Hr. Ex. 118, Att. DEE-1.
[491] Mission:data SOP at pp. 28-29.

with the objective of enabling potential sharing of additional information with VPP and third-party services, while nonetheless retaining customer authorization and consent over the use of their data.

5. Flexible Interconnection Tariff

438. Flexible interconnection refers to approaches that optimize use of existing grid infrastructure by allowing developers to connect new load or generation projects in constrained locations that would otherwise require capacity upgrades. For example, faced with a constrained feeder, an EV charging developer could design operations to reduce load during afternoon peaks but operate at full power in the morning and overnight, when demand is lower and more of a feeder's capacity is available, which might allow the developer to connect without an upgrade. In SB 24-218, the Legislature required Public Service to propose "an optional flexible interconnection or energization tariff or phased interconnection or energization agreement by a customer as an alternative to a system upgrade that would otherwise be required."[492]

439. SB 24-218 also requires qualifying utilities to develop and include as one of at least two planning scenarios "a scenario that incorporates load and managed generation flexibility that may increase system capacity utilization, reduce the need for system upgrades, and lower system costs."

a. Party Positions

440. In response to party contentions that the Company is out of compliance with the above requirements, the Company emphasizes that the statute allows the Company to file either a tariff or a "phased interconnection or energization agreement," which it has done by filing a proposed flexible interconnection agreement in its 2026-2027 Renewable Energy Compliance

[492] § 40-2-132.5(4)(b)(IV), C.R.S.

Plan.[493] The Company suggests that "[i]f the Commission wishes to consider the relative policy merits of a tariff or agreement, it should do so in the RE Plan matter where the Company filed the proposed [flexible interconnection] agreement."[494]

441. The Company states that it is working on several flexible interconnection demonstration projects. The first is a demonstration with Pivot Energy in which it will install a plant controller to control the output of the Company's existing Arapahoe Community Solar Garden.[495] The Company states that it is also going to test flexible interconnection on existing battery assets and that there are existing interconnection applications from dispatchable generators that may reveal system constraints requiring flexible control. The Company is also planning to demonstrate flexible load applications for managed EV charging through the Innovation Portfolio associated with the Transportation Electrification Plan ("TEP") and is planning to advance this objective through the 60-day notice in the TEP proceeding.[496]

442. ACE, Tesla and IREC contend that the Company has failed to comply with statute provisions regarding flexible interconnection, pointing to § 40-2-132.5(2)(u), C.R.S., which defines phased interconnection or energization agreement as "an agreement between a qualifying retail utility and a customer to provide certain levels of electrical service capacity on a guaranteed timeline in exchange for the customer participating in the qualifying retail utility's flexible interconnection or energization tariff while necessary grid upgrades are being completed."[497] These parties argue that since no flexible interconnection tariff has been filed, the Company is out of compliance with § 40-2-132.5(4)(b)(IV), C.R.S.

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[493] *See* Proceeding No. 25A-0194E.
[494] Public Service SOP at p. 32.
[495] Hr. Ex. 127, Chacon Rebuttal, pp. 10-12.
[496] Public Service SOP at pp. 31-32.
[497] ACE SOP at p. 12; Tesla SOP at pp. 13-14; IREC SOP at p. 29.

443. ACE and Tesla note that the flexible interconnection terms the Company filed in its RES case are limited solely to front-of-meter generation, thereby excluding most DER and load. ACE claims this limits the overall value proposition of flexible interconnection and could lead to unnecessary distribution capacity investments.[498] Tesla contends that the Company "needs firm encouragement and regulatory oversight for cost-effective use of existing unused capacity," and notes that flexible interconnection is "in the public interest because it would strategically enable public and fleet charging for EVs to use existing, available capacity much sooner, optimizes use of the [distribution system], and is aligned with multiple public policy goals, including affordability."[499] Tesla claims that it is time for the Company to stop studying flexible interconnection and to start offering it.[500]

444. Calling flexible interconnection one of the most impactful, cost-effective tools available for enabling DER deployment, ACE contends that the Company's failure to offer a concrete tariff or pilot runs counter to its 2022 DSP Settlement Agreement commitments and to SB 24-218.[501] ACE therefore asks the Commission to direct the Company to file an flexible interconnection tariff within 60 days of a this Decision in this Proceeding addressing each of the following:

- Engage in a flexible interconnection stakeholder process that leads to the filing of flexible interconnection tariffs for load and generation;
- Define technical pathways for flexible interconnection and load connection, including acceptable export-limiting or interruptible service strategies and study methodologies;
- Ensure eligibility for community solar and storage projects to participate in flexible interconnection tariff options;

[498] ACE SOP at p. 20.
[499] Tesla SOP at pp. 15-17.
[500] *Id.* at 13-16.
[501] ACE SOP at p. 21.

- Update existing interconnection and load connection procedures and screens to incorporate flexible pathways;
- Require Public Service to publish success metrics, such as the number of projects offered flexible options and the percentage of capacity unlocked through such arrangements; and
- Incorporate findings and best practices from other jurisdictions, including relevant aspects of the New York: National Grid's flexible interconnection pilot, and the Illinois Commonwealth Edison and Ameren pilots.[502]

445. Finally, ACE asks the Commission to require the Company to implement a pilot program in 2026 to test flexible interconnection with at least three third-party owned projects of differing DER types.[503]

446. While it notes the Company's plan to demonstrate limited flexible interconnection functionality via Grid DERMS in early 2026, AEU states that the Company's plan is neither necessary nor sufficient, and urges the Commission to require the Company to take several additional steps to quickly enable flexible interconnection for resources during this DSP, including increasing opportunities for the use of flexible interconnection with static limits, expanding the types of technologies and use cases eligible for flexible interconnection, and adopting California's Limited Generation Profile ("LGP") approach to flexible interconnection.[504] AEU states that in addition to Community Solar Gardens, dispatchable distributed generation and flexible energization for large electric vehicle loads, flexible interconnection can be applied to heat pumps, behind-the-meter battery storage, residential rooftop PV and buildings with smart panels among others.[505] AEU contends that additional flexible interconnection applications will increase flexible interconnection benefits to the grid, developers and ratepayers.[506] It asks the Commission to ensure

[502] *Id* at 22.
[503] *Id*.
[504] AEU SOP at p. 12.
[505] *Id* at pp. 12-13.
[506] *Id*.

that the Company is timely taking steps to expand flexible interconnection opportunities to other technologies, use cases, and customers.

447. Noting Company testimony that the Company is already using static limits to implement flexible interconnection, AEU asks that if the Company's Grid DERMS is delayed beyond Q1 2026, the Commission require the Company to "move ahead with implementing flexible interconnection utilizing static limits."[507] AEU states that such limits can enable flexible interconnection without a need for ongoing real-time communication via a DERMS, for example by utilizing load management control equipment on multifamily building EV charging stations or using autonomous inverter controls for rooftop or community solar to limit system output. AEU also suggests that procedural steps could be built into interconnection agreements that limit a new load's ramp up schedule so that it conforms to the timing of grid capacity availability and cost, rather than creating lengthy and expensive grid upgrades. AEU explains that under LGP, DER agree to reduce generator output at specified times rather than paying to expand system capacity. AEU notes that at hearing, the Company committed to "undertaking a process to consider utilizing an LGP approach."[508]

b. Findings and Conclusions

448. The Company is correct that § 40-2-132.5(4)(b)(IV), C.R.S. requires it to file either "an optional flexible interconnection or energization tariff or phased interconnection or energization agreement". However, ACE, Tesla and IREC are also correct that the definition of the term "phased interconnection or energization agreement" set forth in § 40-2-132.5(2)(U), C.R.S. directly requires the existence of an flexible interconnection tariff:

[507] *Id* at p. 13.
[508] *Id* at p. 14-15.

> Phased interconnection or energization agreement" means an agreement between a qualifying retail utility and a customer to provide certain levels of electrical service capacity on a guaranteed timeline *in exchange for the customer participating in the qualifying retail utility's flexible interconnection or energization tariff* while necessary grid upgrades are being completed. (emphasis added)

449. While we note the Company's filed a proposed flexible interconnection agreement in Proceeding No. 25A-0194E, that agreement is not accompanied by the necessary tariff contemplated by § 40-2-132.5(2)(U), C.R.S. So as an initial matter, we find that the Company's flexible interconnection agreement is not fully responsive to the relevant statutory requirement, and that it must file a flexible interconnection or energization tariff within 60 days of this Decision, that this tariff must conform with the ACE recommendations specified above and that the Company must propose the pilot program ACE recommends.

450. Further, we would like to note our extreme dissatisfaction with the fact that the Company has not already filed a flexible interconnection tariff, as this is an indicator that the Company is failing to plan for the strategic and affordable achievement of the State's transportation and BE and decarbonization goals. As the Commission's investigation into barriers to BE and DERs in Proceeding No. 23M-0464EG demonstrated, the Commission has for several years been encouraging the Company to develop and provide alternatives to customers to speed their ability to connect to the grid in a cost-effective and timely manner.[509] Flexible interconnection would appear to be a very promising alternative to do just that, and yet the Company appears to be dragging its feet to implement flexible interconnection.

451. Furthermore, we agree with AEU that neither the existence of a grid DERMS nor flexible interconnection-specific use cases for a grid DERMS are necessary preconditions for flexible interconnection. The use of static limits, interconnection agreements with appropriate

[509] Decision No. R24-0242-I at ¶ 33, issued in Proceeding No. 23M-0464EG.

terms and California's Limited Generator Profile approach can enable DER and load interconnection by limiting generation or load to existing grid capacity availability prior to the availability of Grid DERMS, thereby improving grid utilization and avoiding or delaying the need for grid capacity upgrades which would certainly be more costly. As AEU notes, Company witness Chacon agreed at hearing to "commit to looking into" the LGP approach.[510] However, this is obviously a good deal short of a Company commitment to implement these low-cost forms of flexible interconnection. We find this to be a matter of urgency, and that a flexible interconnection tariff, and broad availability of flexible interconnection should not be forced to await development of grid DERMS use cases. Accordingly, we require the Company to develop and include in the flexible interconnection tariff filing required above provisions implementing the use of static or scheduled export or load limits, as well as interconnection agreement provisions limiting maximum load ramping so that a new or expanding customer's load growth corresponds with grid capacity availability. We further require that upon determining that the distribution system doesn't have sufficient capacity to accommodate a prospective customer's full load or generation, the Company must inform the customer of the availability of these alternatives to grid capacity expansion. Notably, Proceeding No. 23M-0464EG issued in April 2024 indicated that the Company should also provide for increased transparency and optionality for applicants for service in situations where grid upgrades would be needed to serve them, including a "menu of options that a project team could choose to integrate to potentially reduce, defer, or eliminate the need for an upgrade." A sincere effort to serve customers more quickly and optimize usage of the grid is expected to include this sort of progress.

[510] Hr. Tr. August 29, 2025, pp. 48:22-49:2.

6. Alternatives Analysis for Downtown Denver

a. Party Positions

452. Noting the difficulty and high cost of expanding electric service in downtown Denver, Denver asks that the Commission require the Company to conduct an analysis of the potential for a thermal energy network, or TEN, to defray infrastructure costs across the Company's electric, gas, and steam systems. Denver claims that despite the previous analyses of the potential for an Ambient Loop thermal network, it does not know whether that project is the least cost alternative because the Company has not performed a comprehensive alternatives analysis. Denver notes that its own study suggests that an ambient loop could reduce peak heating demand by at least two-thirds, and contends that this potential should be explored fully. Denver further complains that under its current policy, the Company excludes the downtown network distribution system from eligibility for NWAs, thereby eliminating the consideration of a downtown thermal network as an NWA. Denver recommends this analysis use approved NWA and NPA methodologies as a baseline to develop an integrated approach that considers impacts across Public Service's electric, gas, and steam systems, and incorporate societal, health, and ratepayer impacts. Finally, Denver supports the Company's proposed demonstration of the Encoord platform to optimize planning across its gas and electric systems and asks that the Commission direct the Company to evaluate and report on Encoord's ability to conduct the alternatives analysis.[511]

453. Public Service argues that it is unnecessary for the Commission to require the study Denver requests, because the Commission has already approved a settlement in Proceeding No. 22A-0382ST (Public Service's 2022 Steam Resource Plan) that requires it to assess the potential

[511] Hr. Ex. 700C, Shea Answer, pp. 69-73.

for a thermal network as an alternative as part of its next Steam Resource Plan, which must be filed no later than November 1, 2028.[512]

b. Findings and Conclusions

454. The Company is correct that the settlement in Public Service's 2022 Steam Resource Plan already requires the Company to present in its 2028 Steam Resource Plan much or all of what Denver is asking for here. In particular, paragraph 23 of the settlement agreement approved in Public Service's 2022 Steam Resource Plan requires that the filing include a base case business as usual scenario, a least-cost scenario that supports the State's greenhouse gas reduction targets, and a proposal that transitions current steam customers away from steam service to a lower-carbon alternative. Paragraph 24 requires the Company to provide 1) a technical assessment of alternative technologies, 2) a regulatory assessment of the Company's options and preferred regulatory proposals for the system, 3) a review of cost projections related to the Company's proposals for the steam system, including for the Company's steam, electric, and gas utilities, and the appropriate allocation of such costs among customers, 4) a customer transition assessment including proposed timelines and regulatory approaches to manage the transitions, and 5) a carbon emissions assessment for each alternative.

455. Given these provisions, while we would encourage the Company to conduct and file the study specified in the settlement agreement approved in Public Service's 2022 Steam Resource Plan at the earliest possible date, we decline Denver's request that we require the Company to deviate from the provisions of that agreement as Denver requests in this Proceeding. Nonetheless, Denver's suggestion that the Encoord platform might prove to be a useful tool for

[512] Hr. Ex. 123, McDermott Rebuttal, pp. 19-21. By Decision No. R24-0672, issued in Proceeding No. 22A-0382T, the Commission approved a comprehensive settlement agreement.

the analysis required in the next Steam Resource Plan is reasonable. We therefore direct the Company to evaluate whether the Encoord platform that it has proposed in this Proceeding as a demonstration project is a viable tool to support the alternatives analysis required in the next Steam Resource Plan and to report on its findings in its next DSP application filing.

7. Distribution System Operator Proposal

456. UCA suggests the Commission explore implementation of a Distribution System Operator ("DSO") to identify an organized and logical approach to grid modernization and DER integration. The Commission should explore the potential use of a DSO because it could allow more efficient operation of the distribution system that ensures sufficient infrastructure is planned and built. A DSO could also effectively utilize DER and grid services to avoid or defer more costly utility capital investments.[513]

457. Other parties did not respond to UCA's DSO recommendation.

458. Through this Decision, we are requiring significant improvements in the Company's DSP, including providing Public Service material inducements to facilitate a desirable outcome which maximizes strategic and cost-effective non-traditional resources. That process should be given the opportunity to evolve and take root, at least at this juncture. Accordingly, we reject UCA's proposal for now, but may consider such an approach in the future depending on Company performance implementing this DSP Decision.

8. Regulatory Sandbox

459. The Company explains that this concept, developed by Rocky Mountain Institute (RMI), is a framework for regulatory experimentation that offers the possibility of granting temporary exemptions to existing regulations. The Company explains it is needed because electric

[513] UCA SOP at p. 10.

utilities are not able to innovate fast enough, and that regulation is not adapting quickly enough to meet current challenges. According to Company witness Pollock, New York, Vermont, Hawaii, Connecticut, and Oregon have all implemented this concept in some way and it has gained significant traction in Europe.[514]

460. Staff argues the Commission should reject the Company's proposal to implement a Regulatory Sandbox because it exposes ratepayers to significant risk and reduces Commission oversight. Staff notes that through the Commission's Distribution System Planning Rules, the Company already has a flexible mechanism for pursuing pilot projects. Specifically, Commission Rule 3533 allows the Company to propose pilots and programs aimed at exploring new and innovative distribution activities.[515]

461. The Commission agrees with Staff and rejects the Regulatory Sandbox concept. While we find some merit in the idea of the Company having the freedom to implement innovative programs in order to accomplish the broad goals of the statute, we agree with Staff that the Regulatory Sandbox concept exposes ratepayers to significant risk and reduces Commission oversight at an inappropriate juncture in the Company's distribution planning efforts. This is a particularly poignant concern given the failings of the Company to present appropriate progress in several key areas, as identified, which contributes to an environment where tighter oversight is required. This, combined with the dramatic expansion in activities and spending identified by the Company in this plan require enhanced, rather than loosened Commission oversight at this moment. We believe the Company should first provide indication it can meet the initial

[514] Hr. Ex. 122, Pollock Rebuttal, p. 42.
[515] Staff SOP at pp. 24-25.

expectations of this DSP application including successfully implement the VPP and NWA programs and develop the other requirements referenced throughout this Decision.[516]

9. Comprehensive Assessment

462. Denver argues that the Company is "at the outset of a multi-decade rebuild of its electric distribution system," and that the Commission should therefore be highly confident that the system the Company proposes is the best possible one to meet future needs. Denver argues that the Company has not met its burden of demonstrating that this is the case "at a time when the paradigm has clearly begun to shift." Denver recommends that the Commission direct the Company to conduct a comprehensive assessment of cost-control solutions via additional scenario modeling to identify lowest cost opportunities to meet future needs, explicitly considering potential contributions from TENs, building envelope improvements, distributed energy resources and flexible interconnection.[517]

463. Denver further recommends that the Company be required to study costs and benefits of a long-term transition to a higher distribution voltage. Denver contends that the Company's current design standard was adopted over 20 years ago and did not anticipate load from EVs and air source heat pumps. Denver questions whether a gradual, long-term shift to higher voltage might better serve customers at lower total cost, notes that the Company already operates part of its system at a higher voltage, and argues that given the magnitude of the coming changes, it makes sense to consider and quantify the costs of such long-term options. Finally, Denver recommends the Company be directed to develop a coordinated vision for the future of the

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[516] Commissioner Plant dissents noting that the regulatory process is inherently slow while technological advances are constantly evolving. A regulatory sandbox would allow the Company to test applications of technologies between DSPs and accelerate advancement of innovative applications quickly and efficiently.

[517] Denver SOP at pp. 13-17.

Downtown Denver Network system by studying shifts in projected customer energy use; impacts on the distribution system due to evolution of the gas, steam and chilled water systems; studying how the network system inhibits deployment of NWAs; evaluating the relative cost to upgrade network assets vs. radial assets and the potential reliability impacts of absorbing the network system into the radial system; and reporting on how other utilities with network systems are planning to accommodate electrification and DERs.[518]

464. The Company does not respond to Denver's recommendations regarding distribution voltage or the future of the network system in its SOP. However, in rebuttal testimony, Company witness McDermott states that the Company regularly reconsiders its design standards, but the Company's position is that matters of engineering judgment, like the standards it uses for the design and construction of its feeders and substations, should be left to its engineering judgment.[519]

465. Denver is asking for Public Service to conduct a very broad-ranging study to demonstrate that its vision of the future distribution system is the optimal one. We agree with Denver's sentiment that this DSP reflects the beginning of a long-term transition of the distribution system, and thus is a sensible time to consider whether the system's current configuration is best for the future. However, at this point, neither the Company, the parties, nor the Commission know very much about the true potential contributions of NWAs, VPPs, DERs, flexible interconnection, thermal networks or other non-traditional alternatives that may emerge in the future. Options that seem promising today could prove to offer dramatic capital savings or could prove to be dramatic failures. Because of this, we find that it is premature for the scenario analysis Denver calls for, as

[518] *Id*. at 17-22.
[519] Hr. Ex. 123, McDermott Rebuttal, pp. 22-26.

such analysis would likely simply reflect the multiple assumptions modelers would have to make about the performance of the non-traditional options. We believe it is important to establish a policy environment that is conducive to the success of these technologies, to learn from initial real world applications, and then to adjust investment allocations in the future based on data developed by previous efforts. Accordingly, while it may be warranted in the future, we will not require the comprehensive assessment Denver calls for at this time.

466. With regard to Denver's distribution voltage and topology arguments, we agree with Public Service that the Commission should in almost all cases cede such decisions to the Company. However, we do believe that Denver's contention that given the long-term and very expensive transition that Denver, along with the State, and Company are embarking on, it is sensible to ask the Company to formally assess and justify its judgements on why the current voltage level and topology of its distribution network are optimal going forward. While any changes to these attributes would likely be quite expensive, it is conceivable that they could provide long-term savings for the system as a whole. We therefore direct the Company to provide direct testimony and analysis in its next DSP application addressing the questions Denver raises about distribution voltage and the continued value of network topology.

10. DI/IQ Community Engagement

a. Public Service Direct Case

467. Public Service proposes to expand its current outreach approaches and partnerships, including the RED Truck initiative and partnership with the Latino Community Foundation of Colorado ("LCFC").[520] The Company notes that its outreach plan to the Income Qualified/Disproportionally Impacted (IQ/DI) communities, called "Power Together" (formerly

[520] Hr. Ex. 103, Pollock Direct, Att. ZDP-1, p. 198.

Energize Together), is designed to leverage its partnership with LCFC and provide the targeted communities with resources to reduce financial burdens and facilitate access to clean energy initiatives. Public Service also states it is engaging its communities in a broader effort to identify critical customers and infrastructure.[521] The Company notes that "even though we did not explicitly prioritize our capacity investments to be within DI Communities, more than three quarters of the projects directly benefit DI Communities."[522]

b. Party Response

468. Staff notes that the Company has been directed by both legislation and Commission rules to prioritize DI Communities within its DSP.[523] Staff claims the Company did not specifically prioritize as required by the statute, and that the Company responded to a discovery request that is not yet been able to effectuate necessary changes to how the Company prioritizes asset health and reliability projects given the timing of the DSP,[524] that the Company lacks reliability information specific to DI Communities.[525] Staff argues the Commission should take this into consideration when it evaluates whether the Company "strategically" advances the goals SB 24-218.

469. Staff notes that the settlement reached in the 2022-2025 RES Plan states that "[a]s part of its annual RES reporting on IQ/DI Community matters, Public Service agrees to provide data and reporting on IQ/DI Community participation in renewable energy and storage programming by census block group ("CBG") and program, to the extent technically feasible."[526] That settlement also states that "[a]s part of the IQ/DI Community Engagement and Outreach Plan,

[521] *Id.* at 200.
[522] Hr. Ex. 105, Mino Direct, p. 41.
[523] Hr. Ex. 505, Turner Answer , p. 23.
[524] Hr. Ex. 505, Turner Answer, Att. JDT-3.
[525] Hr. Ex. 505, Turner Answer, p. 29.
[526] Hr. Ex. 505, Turner Answer , p. 32, citing Commission Decision No. C22-0678, Attachment A ¶75, issued in Proceeding No. 21A-0625EG,

Public Service will evaluate how IQ/DI Community earmarked funds will be allocated to support customer outreach and IQ/DI Community program participation." Staff argues the Company's DSP fails to meet the expectations of the RES Plan settlement because it is unclear how its Red Truck outreach approach differs from the Company's standard marketing efforts, that its specifically targets DI Communities, or that it demonstrates a concerted effort to engage with these communities.[527]

470. Staff argues the Commission should direct the Company to develop the following: a comprehensive DI Community Engagement and Outreach Plan and report on it within 60 days of this Decision; a comprehensive DSP Customer Engagement and Outreach plan, and report on it within 90 days of this Decision; and, additional reporting on IQ/DI community engagement identifying participating Community Based Organizations and community leaders, list of priorities/interests, list of programs/projects developed based on engagement efforts, list of prioritized benefits to DI Communities.[528]

471. CEO notes that Commissioner Gilman asked directly about coordination with local, regional and state government entities.[529] However, CEO claims, when asked if any of the proposed stakeholder and community engagement budget in this DSP was for this type of coordination, the Company said that such funding is handled separately from the DSP process through its Area Management group and that it is not aware of plans to expand its engagement with local, regional, and State entities trying to implement policy goals such as affordable housing and electrification. The Company later indicated that it is "trying to be more collaborative with [municipalities] on our planning processes . . . ." CEO argues the Commission should require

[527] Hr. Ex. 505, Turner Answer, p. 36.
[528] Hr. Ex. 505, Turner Answer, pp. 39-40.
[529] CEO SOP at p. 17.

Company to increase coordination and collaboration with local, regional, State government entities specifically for DSP purposes track, and provide information in next DSP about projects being coordinated between Public Service and governments, with description of projects/policy goals supported, and which feeders/substations are implicated. CEO also argues the Commission should approve a narrower budget related to community outreach and engagement that directly addresses statutory requirements.[530] CEO recommends the Commission limit the Company's proposed $6.8 million budget for stakeholder and community engagement and outreach to only the expenditures that directly enable compliance with the DSP statute. CEO admits that value is not entirely clear, but suggests no more than $2.18 million should be approved.[531] CEO explains that amount is proposed by the Company for "Educational/Outreach Programs & Support Materials" and "Engagement" and includes funding for hosting workshops, community meetings, and public seminars; translation services; partnerships with local organizations; and community member compensation.

472. Denver similarly suggests the Commission should direct Company to file annual reports on its engagements with local communities and governments. Denver explains that this report should include descriptions on specific local priorities and projects, collaborative initiatives, and a description of how the Company is incorporating local information into its forecasting.[532]

c. Findings and Conclusions

473. The Commission finds that Public Service's plan to reach out to DI communities via the Red Truck Initiative is adequate, and should be provided the opportunity to implement its proposal. We also note that through this DSP the Company is engaging the private market in new

[530] CEO SOP at p. 19.
[531] CEO SOP at p. 19.
[532] Denver SOP at p. 32.

and innovative approaches via the VPP and NWA processes. Accordingly, the private sector will be also messaging and informing the Public Service customer base regarding opportunities to participate in the overall goal of meeting local distribution needs via demand management and similar mechanisms.

474. Nonetheless, Public Service is required to report on the outreach and engagement efforts performed by the Company, to the extent possible, comment on the private market's ability to engage the customer base over these first critical years of VPP/NWA implementation. Public Service shall work with partners in the private market to ensure that customers receive consistent and clear messaging on available initiatives. The Company should report on these factors as part of its next DSP, or earlier if such information is available. If the Company receives feedback that its DI and broader community outreach is not educating the targeted audience, or somehow providing a confusing message to its customer base, Public Service should address that and offer potential solutions to such in its next DSP.

11. Coordination with Local, Regional and State Entities

a. Party Input

475. CEO argues the Commission should require Company to increase coordination with local, regional and State government entities.[533] According to CEO, the Company should specifically track and provide information in its next DSP about projects being coordinated between Public Service and governments, with description of each projects and the policy goals supported, and identification of which feeders or substations will be impacted, by how much, and by when.[534]

[533] CEO SOP at p. 17.
[534] CEO SOP at p. 18.

476. Boulder suggests the Commission require the Company to assess local conditions on each identified feeder of concern on a case-by-case basis, including meeting with local governments to ensure the Company is informed by local and comprehensive planning, prior to making investments to increase capacity.[535]

477. Denver suggests the Commission should direct Company to file annual reports on its engagements with local communities and governments.[536] Denver notes that Commissioner Gilman's decision in Proceeding No. 23M-0464EG[537] recommended that Public Service partner with local communities in two primary ways: 1) collaborate to improve and accelerate the permitting process for distribution system upgrades; and 2) gather information from municipalities about upcoming projects or local policy drivers that could influence forecasting of capacity needs. Denver also suggests such local considerations were a priority of the Legislature in passing SB 24-218, and that it is only appropriate to require the Company to report on its progress. Denver explains that this report should include descriptions of specific local priorities and projects, collaborative initiatives, and a description of how the Company is incorporating local information into its forecasting.[538]

b. Public Service Response

478. Public Service responds that it regularly meets with municipalities, and plans to continue and improve the collaborative exchange of information, particularly with respect to development plans and expected load growth.[539] The Company contends it already considers local

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[535] Hr. Ex. 1101, Telischak Answer, p. 6.
[536] Denver SOP at p. 31.
[537] *In the matter of the commission's implementation of aspects of senate bill 23-291 including its consideration of customer connections to and disconnections from investor-owned electric and gas utility systems and the study of potential barriers to beneficial electrification and distributed energy resources.*
[538] Denver SOP at p. 32.
[539] Hr. Ex. 123, McDermott Rebuttal, pp. 26-27.

conditions in forecasting and planning to a significant extent, including by using municipal development plans as an input to the allocation of forecasted new load performed in LoadSEER.[540] The Company stated that its engagement funding is handled separately from the DSP process through its Area Management group and that it is not aware of plans to expand its engagement with local, regional, and State entities trying to implement policy goals such as affordable housing and electrification. The Company, however, is opposed to any strict requirement that each and every capacity project have a formal consultation process.[541]

c. Findings and Conclusions

479. The Commission adopts CEO's position of requiring the Company to track and provide information in its next DSP indicating local and other government coordination and listing which feeders and substations were impacted by such. We reiterate that coordination with local entities is critical for planning purposes and that DSP process overall is clearly expected to reduce energization timelines and facilitate faster evaluation and implementation for the development community. The extent to which this communication can improve will only aid in right-sizing the system and ensuring that infrastructure decisions are made with full awareness of expected development, land use patterns, or building code implications. We reject for the purposes of the instant proceeding, annual reporting on the Company's efforts and progress in this area, as proposed by Denver. However, we keep this option open for possible later implementation.

12. Revised Cost Benefit Analysis

480. WRA argues the inclusion of electric system costs in the cost-benefit analyses for non-pipeline alternatives currently acts as a barrier to the selection of these projects.

[540] Hr. Ex. 123, McDermott Rebuttal, p. 27.
[541] *Id.*

WRA contends SB 24-218 requires qualifying retail utilities to upgrade the State's electrical distribution systems as needed and in time to affordably and reliably support the achievement of the State's beneficial electrification and decarbonization goals. For this reason, the Company should proactively plan its electric distribution system in a manner that appropriately accounts for forthcoming non-pipeline alternatives. Accordingly, WRA suggests, the Commission should consider revising cost-benefit analysis processes thru other proceedings such as the GIP in a manner that acknowledges the statutory directive for utilities to plan for beneficial electrification. WRA notes this action is outside the scope of this Proceeding.[542]

481. The Commission notes that this issue is specifically taken up in the ongoing Public Service Gas Infrastructure Plan proceeding, 25A-0220G. While we agree with WRA's last caveat – that this action is outside the scope of this Proceeding, we also agree that this issue needs more thorough evaluation and Public Service should generally be contemplating the cost of electric system upgrades in its cost-benefit evaluations of non-pipeline alternatives. To the extent such electric system upgrades are planned or in implementation phase, it appears reasonable to the Commission that future demand-side management activities should assume that as the baseline condition. We will consider this issue more fully in Proceeding No. 25A-0220G, as suggested by WRA.

13. Application Expenses

482. Public Service requests Commission approval to defer expenses related to consultant work, outside legal counsel, noticing, hearing transcript and overhead costs for this matter at no return, to be brought forward for review and recovery in a future electric rate case.[543]

[542] WRA SOP at p. 20.
[543] Hr. Ex. 101, Ihle Direct, p. 90.

483. The Commission approves the deferral of actual costs for this Proceeding in an interest free regulatory asset for presentation in a future cost recovery proceeding and expressly defers ruling on the appropriateness of recovering these costs until they are properly raised in Public Service's next rate case.

14. Other Issues Not Addressed

484. The Commission denies all requests made in this Proceeding that have not been addressed in this Decision.

J. Additional Reporting Requirements and Regulatory Pathway Forward

1. Additional Guidance for Next DSP Application

a. Reporting on Assets Taken Out of Service

485. Denver notes that while some distribution assets have lifetimes on the order of 50 years, the Company is planning its distribution projects to meet anticipated capacity ten years into the future. Denver notes further that even the most conservative projections are forecasting a doubling of coincident peak by 2050, and suggests that because of this, there could be a lot of residual value in grid assets removed from service in the future. Denver therefore suggests that a process and reporting structure are needed to demonstrate optimal re-deployment of such equipment. Denver recommends that the Commission require the Company to begin reporting on:[544]

- Company practices on redeployment or retirement of distribution assets;
- Details of the age and condition for all major equipment taken out of service each year and whether it has been retired or put back into stock;
- Equipment that has been redeployed each year, along with estimated deferred costs.

[544] Denver SOP at pp. 10-12.

486. We find Denver's recommendations in this area to be sensible practices that should not be costly or burdensome to implement (and may already be standard practice for the Company). We therefore direct the Company to include the reporting described above in its next DSP application.

b. Comparison of Actual to Projected Asset Loading

487. CEO,[545] SWEEP/NRDC,[546] Denver[547] and WRA[548] all request that in its next DSP proceeding, the Company be required to file a comparison of the load levels projected for each asset in this Proceeding to actual measured load levels. These parties contend that such a comparison was required by the settlement agreement from the last DSP proceeding,[549] and that this comparison is necessary to identify key sources of uncertainty and to inform whether forecasting methodologies need to be course-corrected.

488. We support the recommendations of these parties, as we find they will 1) provide insight into the strategic nature of the Company's choices and projects; 2) require the Company to rigorously review the accuracy of its asset-specific forecasts, 3) require the Company to attempt to explain any significant discrepancies if found and modify forecasting methodologies to correct such discrepancies, and 4) provide parties insight into forecasting accuracy, which could advance the discussion in future proceedings. We therefore direct the Company to include in its next DSP application a comparison of projected and actual load levels for each distribution asset for the most recently completed distribution planning year.

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[545] CEO SOP at p. 13.
[546] SWEEP/NRDC SOP at pp. 28-29.
[547] Denver SOP at p. 10.
[548] WRA SOP at p. 26.
[549] Hr. Ex. 112, Unopposed Non-Comprehensive Settlement Agreement, filed on December 8, 2022, in Proceeding No. 22A-0189E, at ¶ 5.2.

c. Disclosure of Asset Loading Models

489. SWEEP/NRDC recommend that the Commission require the Company to preserve and disclose its models underlying asset loading assumptions and identify key sources of uncertainty in the models. SWEEP/NRDC contend that this is necessary to enable replicability and scrutiny of the Company's forecasting methodology.[550]

490. We agree that disclosure of asset loading models, with any necessary confidentiality protections, will enable party scrutiny and potentially valuable additional insight into the Company's asset loading methodologies. We therefore direct the Company to provide asset-specific models as an appendix to its next DSP application.

d. Consolidated Presentation of LoadSEER Assumptions

491. WRA asks for improved presentation of LoadSEER modeling assumptions, stating that some assumptions were only available through follow-on filings or discovery. WRA asks that in the future all relevant information about LoadSEER inputs be consolidated in a single place.[551]

492. We agree that neither the parties nor the Commission should have to identify the Company's modeling assumptions via supplemental direct requirements or discovery requests. We therefore require the Company to present all LoadSEER modeling assumptions in a single consolidated document in its next DSP, filing confidential versions only as necessary.

e. Seasonal Rating of Distribution Assets

493. At the March 13, 2025 Technical Conference, Commissioners raised the question of whether distribution components have constant ratings across the year or whether it would make sense to adopt seasonal ratings (similar to the concept of dynamic line ratings in transmission).

[550] SWEEP/NRDC SOP at pp. 28-29.
[551] WRA SOP at p. 27.

Company witness Steven Martz discussed that this is an appealing, but nascent concept, and also noted that a circuit's rating is determined by all components, from the substation transformer to the end of a feeder, and so any seasonal variation would need to reflect the most limiting element in a circuit. Martz also noted that the Company was reaching out to winter-peaking utilities to better understand their practices in this regard.

494. As the Company has indicated that its peak load may shift to winter as soon as 2032,[552] we find it sensible to evaluate whether there is sufficient seasonal variability in distribution asset capacity to adopt seasonal rather than annual ratings in determining the necessity of capacity expansion projects. We therefore direct the Company to conduct research into utility best practices regarding seasonal distribution asset rating and to report on this research in its next DSP Application. This research should include the practices of winter-peaking utilities, recommendations of equipment vendors, and the experience of other relevant experts.

f. Reporting on Distribution Asset Loading

495. In figure BDM-R-1 of her rebuttal testimony, Company witness McDermott presented data on the number of feeders in each planning division that were below 75 percent loading, between 75 and 100 percent loading, and above 100 percent loading. The Commission found this information to be informative and helpful, and so directs the Company to provide a table similar to Table BDM-R-1 in its next DSP application. This table should group feeders into loading intervals that are 12.5 percentage points wide (rather than 25 points wide) so that the Commission has a more precise illustration of system stress and capacity. We further require the Company to file a spreadsheet with its direct testimony presenting the most recent measurement of

[552] Hr. Ex. 103, Pollock Direct, Att. ZDP-1 Rev. 1, pp. 57-58.

non-coincident peak loading on each feeder, bank and transformer, percentage of the planning load limit for each such asset, and load growth on each asset since the filing of this Proceeding.

g. Transmission Costs Related to Distribution Investments

496. UCA asserts that the 2025 Rule 3206 Report (Rule 4 CCR 723-3-3206),[553] filed well after this DSP Application,[554] contains no information on transmission investments needed for the majority of the 35 new substations the Company proposes, and suggests that the needed transmission could double the costs of these projects. UCA contends that intervenors need to be able to review these costs to determine whether the individual costs and total cost are reasonable and should be approved, and further that the Commission should understand the connected transmission costs that are caused by an increase in downstream distribution capacity.[555] UCA therefore recommends that the Commission require the Company to provide more information on each of the substations and projects included in the DSP.

497. The Company did not address this UCA recommendation in its SOP. In rebuttal testimony, Company witness Brenda McDermott responds to UCA's recommendation by arguing that transmission needs associated with new substations cannot be determined until the substation location and design process is fairly advanced. McDermott argues that UCA's proposal to require inclusion of transmission and other details prior to distribution budget approval would slow the process and contravene the legislative purpose of making distribution planning proactive.[556]

[553] Pursuant to Commission Rule 4 CCR 723-3-3206(d), A utility must file an annual report no later than April 30 each year that lists transmission facilities that the utility expects to construct in the next three years.

[554] Public Service's 2025 Rule 3206 Report was filed April 30, 2025 in Proceeding No. 25M-0005E.

[555] Hr. Ex. 603C, Neil Answer, pp. 6-13; UCA SOP at pp. 6-7, citing Proceeding No. 25A-0409E.

[556] Hr. Ex. 123, McDermott Rebuttal, pp. 7-12.

498. Commissioner Gilman questioned McDermott about the absence of transmission-related costs at hearing. McDermott verified that no transmission-related costs are included in the budgets presented in this Proceeding but stated that the Company has high-level scoping estimates of such costs for projects planned for the next few years.[557]

499. As these costs are imposed on ratepayers by the distribution investments they support, we find it critical that the Company present its best estimates of transmission costs related to its DSP so that the Commission and others can have a complete understanding of the total costs of a DSP. We therefore direct the Company to make a filing in this Proceeding within 30 days of this Decision presenting the Company's best estimate of transmission costs imposed by the distribution investments presented in this DSP. We also direct the Company to include a description of how the Company proposes to recover such costs. Finally, we direct the Company to include estimated transmission costs in future DSP applications.

h. Rate Forecasts, Load Shapes and Capital Spending by Rate Class

500. Finally, we direct the Company to provide the following as components of its next DSP application:

- 20-year rate forecasts utilizing the Company's most current capital spending plan, the most recently approved customer class allocators, and customer usage for each rate class based on the load forecasts presented in the DSP application.
- One or more executable spreadsheets containing the following information:
    - 8,760 hourly load forecasts (365 days x 24 hours / day) and summary 12 x 24 forecasts (averaging loads in each hour in each month) for three customer classes: the residential class, the classes that comprise the GMAC customers, and all retail customers. These forecasts should be provided for the years 2026, 2030, 2035, 2040 and 2045.
    - For each forecast year (2030-2045), additional 8760 and 12 x 24 matrices presenting load associated with beneficial electrification, behind-the-meter solar, EVs, and remaining contributions to load. In

[557] Hr. Tr. August 27, 2025, pp. 22:16-24:20.

doing so, please back out the growing load from each category from the requested matrices and present the resulting revised forecasted matrices.

- Five years of historical capital spending by rate class for each major category of spending included in the proposed capital budget (*e.g.*, Capacity, Asset Health & Reliability, Tools & Communications, etc.).

2. Next DSP Filing Deadline and Filing Requirements

501. Pursuant to Commission Rules, a DSP shall be filed every two years. Accordingly, the next filing would be due December 2026. On Rebuttal, Public Service proposed a three-year cadence for its next DSP (which would be filed in November 2027 for the years 2029-2033 (but only approve spending through 2031). This cadence would result in a 3-year approval in the instant case. [558] Ihle suggests the Company would be challenged to develop another DSP, incorporate the recommendations by parties, and file a new DSP in the fall of 2026. Starting with three years here provides sufficient time for incorporation of these recommendations, with a two-year cadence to follow after that.[559] The Company also proposed GMAC filings in November of 2025 and 2026 and a true-up in April 2027.

502. The Company suggests that to the extent the Commission believes a variance is necessary to implement this cadence, particularly for the November 2027 DSP, the Company asks that the Commission grant such variances as part of its final decision in this Proceeding.[560]

503. The Commission adopts the Company's proposed DSP filing cadence. We believe it will provide the time necessary to facilitate meaningful improvement in the Company's next DSP application, including but not limited to: development of the performance-based framework the Commission is considering; implementation of the VPP and NWA programs with associated

[558] Hr. Ex. 121, Ihle Rebuttal, p. 77.
[559] *Id.*
[560] *Id.* at 79.

learnings such as drivers to success of those programs; and development of the HCA data and maps.

504. Furthermore, the Commission notes that a November 2027 filing allows for inclusion of modeling of the consumer sided resources and projections included in the 2026 consolidated DSM/BE/CHP/OBF filing and the separate 2026 TEP filing. It is the desire of the commission to establish an ongoing cadence that plans the electric system from the customer outward with consumer sided resources informing the next DSP and the next DSP informing the next Electric Resource Plan. To the extent the company can maintain this rolling cadence of three-year proceedings, it will allow for a logical and strategic planning of the electric system. Relatedly, the Commission requests the intervening parties in the 2026 TEP and Consolidated filings include recommendations regarding how outcome of those proceedings can be most effectively modeled and used to inform the planning in the next DSP. The Company should keep in mind, in preparing for the next DSP filing, the Commission's expectation that they will incorporate the outcomes of the interim proceedings as listed above.

505. Further, SB 24-218 requires the Commission to open a new rulemaking to evaluate and establish four components including 1) average and maximum energization targets; 2) updates to interconnection rules; 3) rules for cost projection timelines and accuracy and construction schedules for the interconnection, energization and electrification of end-uses in new construction homes; and 4) cost caps or fees associated with resource interconnection or end-use energization.[561] SB 24-218 also requires that such a rulemaking must "conclude in a time that is sufficient to allow the qualifying retail utility to file its second distribution system plan" following the statute's

[561] § 40-2-132.5(6)(a), C.R.S.

passing.[562] The Commission finds that the statutory requirements for a new rulemaking further support the Company's altered cadence for its next DSP.

3. Expanding Record to Examine GMAC Eligibility Performance Metrics

506. In this Decision, the Commission has found the Company has failed to show that certain costs would further GMAC purposes in an affordable and strategic manner. Based on that overall finding, we did not allow GMAC recovery of all categories proposed for such favorable recovery, and determined it appropriate to condition future GMAC recovery pursuant to 40-2-132.5(7)(b)(III), C.R.S. Specifically, for the 2027 and 2028 implementation of this DSP, we will evaluate Public Service's ability to improve performance in several ways including: interconnection and energization time frames; system reliability (*e.g.*, those metrics required in QSP reports); customer service (*e.g.*, those referenced in Hearing Exhibit 2307 [Staff investigation into customer care]); HCA data availability and usability; availability of a Flexible Interconnection tariff; and ways that demonstrate reduced distribution system peaks through effective use of VPPs, EV charging, temperature control equipment, and other approaches that dynamically manage demand and supply in real time , using appropriate metrics such as percentage increase in distribution asset utilization, distribution system load factor, or other metrics as appropriate.

507. The Commission recognizes that the Company proposed an interconnection metric in its direct case but found little, and largely not fully developed, response to that proposal on the record (perhaps due to the extraordinary number of issues raised here). We also recognize that the performance goal of reduced peak load impact of VPP, EV and BE technologies may require more time to implement associated programs to accomplish and broadly facilitate. Accordingly, we find

[562] § 40-2-132.5(6)(c), C.R.S.

it necessary to expand the record in this Proceeding on the issue of appropriate metrics to evaluate and encourage Public Service to improve performance in these critical areas. We invite Public Service to propose verifiable metrics to accomplish this goal, and for parties to comment on that proposal, so that the Commission may establish an evaluation protocol relevant to 2027 GMAC eligibility (without consideration of peak load impact of VPP, EV and BE) and 2028 GMAC eligibility (with consideration of peak load impact of VPP, EV and BE peak load impacts).

508. In evaluating Public Service's proposal and party comments to that submission, the Commission seeks clarity on the following facets of metric implementation:

- What is the specific calculation approach?
- What is the appropriate baseline for evaluation of performance improvement (*e.g.*, historic year or average year, national average)?
- How should tiers of performance be measured, categorized and applied to recovery (*e.g.*, individual metric percentages, bands of performance such as "doesn't meet", "meets", "exceeds" or another approach)
- If performance needs to exceed the baseline, by what percentage(s) or numerical value(s) (*i.e.*, if one or multiple tiers are applied)?
- How should the Commission combine or weigh these metrics to determine an overall GMAC eligibility of non-capacity investment?

509. The Commission also notes that we found initial merit in Staff-derived versions of reliability metrics that eliminate adjustments to raw data due to weather or circumstances otherwise outside of the Company's control. We recognize extraordinary events could lead to high variability in annual data; we invite comment on that concept and options to smooth out such variability. We establish a deadline of February 1, 2026 for Public Service to submit its proposal as part of this DSP Proceeding and set the ultimate performance based GMAC additional Type 2 accelerated cost recovery at a not-to-exceed capital spending level of $100 million for the November 1, 2026 GMAC filing for 2027 investments and at a not-to-exceed capital spending amount of $200 million

for the November 1, 2027 GMAC filing for 2028 investments. Parties will have 30 days to comment, and Public Service will have 15 days to respond.

4. Annual Reporting

510. Public Service did not propose annual reporting of any kind. With respect to reliability metrics, the Company suggests the Commission should continue to use the QSP proceeding to review reliability and other metrics, and that duplicative reporting should be avoided.[563] With respect to targeted undergrounding, Public Service also suggests that relevant progress be reported upon in the Company's next DSP; however, that program is scheduled to begin in 2026 and will still be in the early stages in 2027.[564]

511. Staff suggests the Commission should order the Company to file an annual report in the most recent DSP docket by June 1 of each year. Staff explains this is especially important given Company Witness Mino's testimony that the Company "locks in" forecast assumptions when it enters into the forecasting process, typically end of the fall, beginning of the winter time period.[565]

512. Denver recommends that the Commission direct the Company to collect and report data on the energization and interconnection process for customers including: costs presented to customers for both conceptual and formal applications with corresponding final costs where applicable; and, energization timelines for all projects to elucidate all steps in the process whether within or outside of Company control.[566] Denver further recommends that the Commission direct

[563] Public Service SOP, at pp. 28-29.
[564] Public Service SOP, at p. 29.
[565] Staff SOP, at p. 23.
[566] Denver SOP, at p. 13.

the Company to itemize details when providing cost estimates to customers, clearly indicating the customer's responsibility.

513. The Commission's DSP Rules do not require annual reporting for DSPs like they do for other application types (likely because the 2-year filing cadence makes an annual report somewhat redundant). However, because the Commission in this Decision grants the proposed 3-year filing cadence, discussed above, we find it necessary to require an interim report as suggested by Staff. We agree with the reporting items suggested by Staff and Denver. We also find it necessary to specify that the annual report should include:

- Budgeted and actual investment by all primary and secondary categories referenced in the DSP;
- Budgeted and actual feeder miles improved, poles replaced, feeder miles undergrounded, transformers improved and replaced, substations improved or replaced;
- Budgeted and actual residential and commercial customers energized (number and MW);
- Budgeted and actual distributed generation systems interconnected (number and MW);
- VPP implementers, customers and MW signed up via VPP program; and,
- A thorough review of VPP milestones and testing metrics per the VPP settlement.

K. Issues Raised in this Case for Future Consideration: Utility Financial Incentives Under Cost-of-Service Regulation and the Potential Impact on Customer Service, System Planning, Capital Spending, and Affordability

514. This Proceeding has begun to surface multiple potential concerns involving the Company's financial incentives under existing regulation and the impact on the Company's spending proposals. Although the Commission has not relied upon these broader concerns in reaching its decision in this case, it nevertheless seems worthwhile outlining them in this order to potentially help guide future processes. Regarding the Company's financial incentives, under

cost-of-service regulation in Colorado, it often seems like investor-owned utilities may be able to increase their short-term earnings by reducing O&M expenses between rate cases. Given this reality, the Commission is increasingly concerned that the material outage, customer service, interconnection, energization, and billing concerns raised in this case may be, in part, a result of the Company's financial incentives to limit O&M spending.

515. In addition, and perhaps much more concerning, existing cost-of-service regulation in Colorado directly links utility earnings with the growth in capital spending and rate base. Given this powerful financial incentive to increase capital spending, the Commission is concerned that the Company's approaches to managing customer usage are resulting in much higher levels of capital spending than those that would prevail if better approaches were adopted. To illustrate this point, and as has been previously discussed in this order, the Commission is concerned that the Company's approach to managing EV charging and beneficial electrification is structured in ways that may disproportionately result in customer load appearing on the system peak such that capital spending, rate base and earnings growth are higher than would be required if significantly better efforts to manage customer usage were implemented.

516. The Company's approach to capital budgeting and managing customer usage off the system peak may not appear too unreasonable in the context of any individual TEP, CHP or other proceeding. And, indeed, the Commission has often historically deferred to the efforts of the Company and the partes to resolve the contested issues in these cases despite finding that these

proposed approaches may often be significantly sub-optimal in terms of appropriately managing customer BE[567] and EV[568] usage away from the system peak.

517. Given the Company's projected capital budgets put forward in this case and the JTS, however, the Commission is concerned that the cumulative net impacts of these multiple sub-optimal efforts to manage customer usage are just now becoming clear in the projected load shapes, capital budgets, and longer-term rate impact analyses. For example, the low demand growth rate impact model shows that from 2025 to 2029, the Company is projecting that it needs to spend a total of over $23 billion in capital to meet system peak demand, divided roughly equally between generation, transmission, and distribution investments.[569] To put this proposed capital spending into context, the Company's total current Colorado rate base is now roughly $12.6 billion.[570] As such, this projected 2025-2029 capital spending represents an enormous increase, which grows the Company's projected Colorado rate base to just under $30 billion in 2029[571] and increases projected Company earnings from under $700 million in 2024[572] to over $1.6 billion in 2029.[573]

518. At the most fundamental level, the Commission is concerned that these capital spending levels may quickly make electricity unaffordable to large numbers of Colorado customers. With actual average residential rates in 2024 of $.138 / kwh (as documented in the

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[567] *See, e.g.,* Public Service 2023 Clean Heat Plan, Proceeding No. 23A-0392EG, Decision No. C24-0397, pg. 63-64 (finding that the Company's proposed approach was limited and increasing proposed spending on new electric-only construction by a factor of six).

[568] *See, e.g.,* Public Service 2023 Transportation Electrification Proceeding No. 23A-0242E, Decision No. C24-0223, ¶ 105, pp. 44-45 (finding that the proposed managed charging incentive was "troubling", that more needed to be done, and tripling the incentive).

[569] See Hr. Ex. 110, Attachment JWI-5, "RevReq" tab, cells d5 to i19 (low load longer-term rate forecast capital budgets)

[570] *Id*. at cell D21.

[571] *Id*. at cell I21.

[572] *Id*. at cell D32.

[573] *Id*. at cell I32.

Company's 2024 SEC 10-K filing),[574] the low case financial model projects that average residential rates will increase by roughly 55 percent to $.214 / kwh in 2029.[575] Moreover, this projected rate comes from the Company's low-load growth forecast, which appears to include retail sales growth assumptions that may be as much as ten times greater than actual historical sales growth since 2010. In the lower load growth scenario, which assumes that retail sales growth may only triple historical levels, the 2029 average residential rate is projected to be $.234 / kwh[576] or roughly 70 percent higher than in 2024. Despite the size of this potential rate impact, the Company has repeatedly told this Commission that it is not willing to accept any sales risk.

519. Although there are obviously all kinds of uncertainties associated with these projections, and the Company has cautioned us about the potential limitations of contrasting actual 2024 data with the projections,[577] the Commission nevertheless remains concerned that the Company's vision of the future that was presented in this case and the JTS proceeding may ultimately not be affordable for many Colorado customers. Given these concerns, the Commission may want to explore additional ways to ensure that customer rates remain affordable, particularly by more closely scrutinizing Company efforts to manage customer usage during system peak in future TEP, CHP, DSM, distributed solar, and rate case proceedings.

II. ORDER

A. The Commission Orders That:

1. The Application for Approval of its 2025-2029 Distribution System Plan and Grid Modernization Adjustment Clause filed by Public Service Company of Colorado ("Public

[574] See Hr. Tr. August 25, 2025, at pp. 159-166.
[575] See Hr. Ex. 110, Attachment JWI-5, "Class Allocation" tab, at cell J113.
[576] See Hr. Ex. 110, Attachment JWI-6, "Class Allocation" tab, at cell J113.
[577] See Hr. Tr. August 25, 2025, at pp. 161, lines 4-22.

Service") on December 16, 2024, is granted in part, and denied in part, consistent with the discussion above.

2. The Application for Approval of an Aggregator Virtual Power Plant, ("AVPP") filed by Public Service on January 31, 2025, in Proceeding No. 25A-0061E, as modified by the settlement agreement filed on August 15, 2025, is granted in part, and denied in part, consistent with the discussion above.

3. The settlement agreement addressing non-wires alternatives and targeted demand areas issues filed by Public Service as Hearing Exhibit 132 on August 15, 2025, is granted, consistent with the discussion above.

4. The settlement agreement addressing AVPP issues filed by Public Service as Hearing Exhibit 131 on August 15, 2025, is granted, consistent with the discussion above.

5. The Motion to Approve Comprehensive AVPP Settlement Agreement, Motion to Approve Unopposed NWA-TDA Settlement Agreement, Notice of Partial GMAC Stipulation, Unopposed Motion for Variance of Settlement Testimony Deadline, and Unopposed Request to Shorten Response Time filed by Public Service on August 15, 2025,[578] is granted in part, and denied in part, consistent with the discussion above.

6. The Omnibus Motion for Extraordinary Protection of Highly Confidential Information and For a Partial Variance from Rules 3528(c) and 3527(b)(VI), filed by Public Service on December 16, 2024, is granted, consistent with the discussion above.

7. The Motion for Penalty on Public Service Company of Colorado Pursuant to § 40-7-105, C.R.S., filed by Mission:data Coalition on July 28, 2025, is denied, consistent with the discussion above.

[578] The Company filed a revised version of the Settlement Motion on August 18, 2025.

8. The Motion for Variance to file a revised statement of position, filed by Tesla, Inc., on September 30, 2025, is granted.

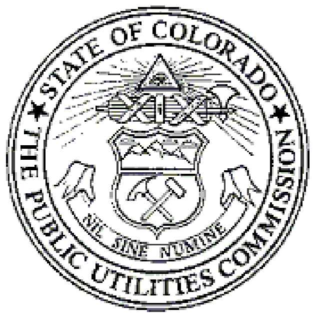
9. Public Service shall file in a new proceeding, an advice letter and tariff on not less than two business days' notice. In calculating the proposed effective date, the date the filing is received at the Commission is not included in the notice period and the entire notice period must expire prior to the effective date. The advice letter and tariff must comply in all substantive respects to this Decision, and shall match the filing made on December 8, 2025, in order to be filed as a compliance filing on shortened notice.

10. The 20-day time period provided pursuant to § 40-6-114, C.R.S., to file an Application for Rehearing, Reargument, or Reconsideration shall begin on the first day after the effective date of this Decision.

11. This Decision is effective immediately upon its Issued Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING ON OCTOBER 29, 2025, NOVEMBER 5, 2025, NOVEMBER 19, 2025, AND DECEMBER 10, 2025, AND AT COMMISSIONERS' DELIBERATIONS MEETINGS ON OCTOBER 23, 2025 AND OCTOBER 30, 2025.

(S E A L)



ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners