Decision No. R21-0387

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 20R-0516E

IN THE MATTER OF THE PROPOSED AMENDMENTS TO RULES REGULATING ELECTRIC UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-3, RELATING TO DISTRIBUTION SYSTEM PLANNING.

RECOMMENDED DECISION OF
HEARING COMMISSIONER
MEGAN GILMAN
AMENDING AND ADOPTING RULES

Mailed Date: July 8, 2021

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I. STATEMENT

1. This rulemaking satisfies the requirements of Senate Bill (SB) 19-236, codified at § 40-2-132, C.R.S., requiring the Commission to adopt rules regarding Distribution System Planning. Specifically, SB 19-236 directs the Commission to promulgate rules establishing, for the first time, that utilities must file Distribution System Plans (DSPs) and evaluate Non-Wires

Alternatives (NWA). Section 40-2-132, C.R.S., specifies that the Commission shall promulgate rules establishing the filing of a DSP, and that the rules must include:

1) a methodology for evaluating the costs and net benefits of using Distributed Energy Resources (DER) as NWA;

2) a determination of the threshold for the size of new distribution projects requiring NWA analysis for any new neighborhood or housing development; and

3) a determination of what information should be set forth in a DSP filing, including the consideration of NWA regarding new development (greater than 10,000 residences), the consideration of increases in load forecasts resulting from beneficial electrification programs, a forecast of DER growth, a summary of the utility's planning process for cyber and physical security risks, a proposed cost-recovery method, anticipated new distribution system expansion investments, a process to evaluate DSP feasibility and economic impacts of NWA for certain projects, and an estimate of peak demand growth or DER growth that merits analysis of new NWA projects.

Section 40-2-132, C.R.S., also provides that the Commission may adopt criteria, benchmarks, or accountability mechanisms to evaluate the success of any NWA investment authorized pursuant to a DSP.

2. On December 3, 2020, the Colorado Public Utilities Commission issued a Notice of Proposed Rulemaking (NOPR) to amend the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* 723-3 (Electric Rules). The proposed amendments develop these new rules regarding DSP.[1] The Commission noticed the proposed rules, provided with Decision No. C20-0837, available to the public through the Commission's Electronic Filings (E-Filings) system.

3. The Commission has developed these proposed rules to enhance transparency and accountability in the DSP process. To be an effective tool, a Distribution System Plan needs

[1] Decision No. C20-0837 (issued on December 3, 2020).

to be comprehensive in terms of examining the entire grid and all the potential options for improving the grid from a reliability, resilience, and cost effectiveness standpoint. We stress that utilities must also enable the safe and timely interconnection of DERs by customers and third parties and strive to optimize the use of new resources, NWAs, and emerging grid technologies, while reasonably balancing the risks and opportunities.

4. The NOPR adopted a schedule for filing comments and invited interested participants to file initial comments no later than January 29, 2021 and to file reply comments no later than February 19, 2021. A public rulemaking hearing was scheduled for March 11 and 12, 2021. The Commission referred this matter to Hearing Commissioner Megan Gilman to preside over rulemaking hearings and for the issuance of a recommended decision.[2]

5. On January 29, 2021, initial comments were filed by the City and County of Denver (Denver); the Colorado Energy Office (CEO); Tri-State Generation and Transmission Association, Inc.; the Advanced Energy Economy Institute (AEEI); Western Resource Advocates (WRA); the Colorado Solar and Storage Association and the Solar Energy Industries Association (COSSA/SEIA); Southwest Energy Efficiency Project (SWEEP); Black Hills Colorado Electric, LLC (Black Hills); the Colorado Office of Consumer Counsel (OCC); the Colorado Energy Consumers Group (CEC); Karey Christ-Janer; Public Service Company of Colorado (Public Service); and on February 5, 2021 by the City of Boulder (Boulder).

6. On February 19, 2021, reply comments were filed by CEO, AEEI, WRA, OCC, CEC, Public Service, SWEEP, COSSA/SEIA, Black Hills, SunShare, LLC (SunShare), and WRA.

[2] Decision No. C21-0108-I issued February 26, 2021, Ordering Paragraph II.A.1 at page 1.

7. A public comment hearing was held on March 11, 2021.

8. On April 9, 2021, Closing Comments were filed by Boulder. On April 16, 2021, post-hearing comments were filed individually by WRA, CEC, Black Hills, Karey Christ-Janer, Denver, COSSA/SEIA, Public Service, and Joint Post-Hearing comments and redline rules were filed by AEEI, CEO, COSSA/SEIA, SWEEP, and WRA (the Joint Stakeholders).

9. Additional written comments were filed on April 27, 2021 by COSSA/SEIA, April 29, 2021 by Black Hills, and May 7, 2021 by Public Service.

10. By these rule amendments, we lay out the objectives of the DSP process and set forth the mechanisms to accomplish those objectives, including a two-phase application that draws on principles from the Commission's industry-leading electric resource planning (ERP) process and a web portal developed based on stakeholder engagement. With this framework as a starting point, we anticipate that utilities' capabilities related to DSP, and the interactions between DSP and other planning processes, will evolve over time.

II. FINDINGS AND DISCUSSION

A. Adopted Rule Amendments. Rule 3525. Applicability.

11. Proposed Rule[3] 3525 describes the applicability of the DSP Rules.

12. CEO recommends that the applicability section be clarified to include language specifying that electric utilities subject to the DSP Rules are those that own "distribution facilities."[4] CEO's proposed changes also make clear that in particular, these rules do not apply

[3] A "Proposed Rule" number corresponds to the Electric Rules proposed for adoption as shown in the attachments to this Decision.

[4] CEO Initial Comments p. 3. January 29, 2021

to the municipally owned electric utilities and cooperative electric associations that have voted to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-104, C.R.S.

13. We agree with CEO's rationales and make the subsequent editorial changes.

1. Rule 3526. Overview and Purpose.

14. Proposed Rule 3526 summarizes the general purpose of a DSP proceeding. After reviewing the proposed rule language, as well as the many comments supporting the need for purpose statements, we believe the purpose of a DSP is to conduct a transparent review of utility investments in the distribution grid to ensure that they cost-effectively support grid adequacy, reliability, and resilience, while simultaneously supporting diversification of energy supply through DERs, expanding the utilization of NWA that reduce the need for conventional distribution grid investment, and preparing for new expectations upon the system. DSP will yield quantitative and qualitative benefits, ranging from integrating grid technologies that support reliability and resiliency, emissions reductions, energy efficiency, demand flexibility, and load management, and will continue to modernize grid monitoring and control technologies and processes. DSP is intended to be complementary to, but not a replacement for, existing Demand-Side Management (DSM) planning and programs and/or distributed generation acquisition processes approved as part of Renewable Energy Standard (RES) plans, as well as Transportation Electrification Plans which are themselves elements of ERP.

15. Public Service recommends minor modifications to reinforce that the expansion of NWAs should not be the goal of the process. Rather, DSP Rules should provide a forum for the evaluation of such an option and its cost effectiveness.

16. CEO recommends changing the word "review" to "review and evaluate," as to better reflect that the Commission will be active in its assessment of the plan. Second, CEO

recommends adding that one purpose of a DSP is to support state policy goals, including reducing greenhouse gas (GHG) emissions. CEO also suggested clarifying the term "new expectations upon the system" by replacing it with "new technologies on the system."

17. WRA argues it is important to articulate that a distinct goal in Rule 3526 is emission reductions due to DER program design and deployment, which can impact the emission reduction benefits of DERs.[5] WRA argues the Commission should strive to utilize DER in a manner that maximizes emission reduction potential. COSSA/SEIA agrees with WRA and CEO, arguing that Rule 3526 should recognize the carbon reduction benefits of DSP.[6]

18. The Joint Stakeholders, in their Post-Hearing Comments, support CEO's recommended changes to Rule 3526,[7] which they argue better clarify the purpose of DSP Rules that the Commission strove to establish in Decision No. C20-0837.

19. We agree with the Joint Stakeholders regarding the need for some limited modifications and make several of their subsequent editorial and clarifying changes. We elected, though, to retain the phase "new expectations on the system" rather than the proposed "new technologies on the system." While we may see new technologies emerge in the coming years, "new expectations" is a more appropriate characterization of the entirety of the upcoming changes. In large part, we may see existing technologies deployed in a more extensive way or with increased customer interaction, setting up new expectations on the system and system operator, whether or not the technologies themselves are new. In addition, we add language stressing the importance of transparency and the timely sharing of information as key aspects of

[5] WRA Initial Comments pp. 4-5. January 29, 2021

[6] COSSA/SEIA Initial Comments, p. 7. January 29, 2021

[7] Joint Stakeholders Post-Hearing Comments, p. 5. April 16, 2021

the distribution system, as increased information-sharing is an important part of developing NWA solutions and DER deployment in line with state policy goals.

2. Rule 3527. Definitions.

20. SB 19-236 requires the Commission to define Distributed Renewable Electric Generation, Energy Storage Systems Connected to the Distribution Grid, Microgrids, Energy Efficiency Measures, and Demand Response Measures. It also requires us to define Non-Wires Alternatives. The Commission proposed 18 new definitions modeled after the proposed definitions submitted by participants in the DSP Stakeholder Outreach Proceeding. The Commission also added "Demand Flexibility" and "Locational Value" to proposed Rule 3527. The Commission found that it is important to provide a definition for Demand Flexibility as a unique concept from traditional Demand Response.

21. In Initial Comments, CEO, WRA, and COSSA/SEIA provide several recommendations for language changes and additional definitions. In Post-Hearing comments, the Joint Stakeholders provide summaries and recommendations previously developed in Initial comments by the participants. First, the Joint Stakeholders recommend "Capacity Need" remove the qualifier "load growth," as factors other than load growth could lead to constraints on the system that could require updates or changes that should be included in DSP plans.[8] The Joint Stakeholders also recommend the Commission modify the requirement in the definition of "Demand Flexibility" so that it includes projects that deliver end-use services at the same or better quality and deliver "net benefits to the system, customers, or society," instead of requiring a project to deliver end-use services at a "lower cost." The Joint Stakeholders believe this helps clarify that benefits accruing to various entities shall be considered in addition to costs, which

[8] *Ibid.* p. 6.

will allow for reasonable expenditures for demand flexibility projects, as long as the benefits of the projects outweigh the costs.[9]

22. The Joint Stakeholders also request the Commission clarify that a "Major Distribution Grid Project" refers to any planned, proposed, or potential capital projects, ensuring that all three stages of grid projects are considered for NWAs. In addition, they suggest the Commission eliminate the last sentence in the definition of "major distribution grid project" as unnecessary as it is explained in paragraph 3534(a) addressing NWA Suitability Screening.[10]

23. In its Initial Comments, CEO requested the Commission remove the qualifier "load growth" from the definition of "capacity need." CEO believes that several factors other than load growth could lead to constraints on the system that could require updates or changes that should be included in DSP plans. CEO also suggests the Commission modify the definition of "energy efficiency measures" to clarify that energy efficiency measures are implemented through programs and projects, and do not include all actions that result in a decrease in electricity usage of customers, such as conservation efforts.[11] CEO also requested a change to the definition of "hosting capacity" to remove the word "significant" when referring to infrastructure upgrades. As written, this term is not defined, thus CEO believes that the meaning is not clear, and it would be appropriate for the utility to report all hosting capacity on the system that would not require any upgrade. The Joint Stakeholders adopted these recommendations in Post-Hearing Comments.

[9] *Ibid*. p. 6.
[10] *Ibid.* p. 7.
[11] CEO Initial Comments, p. 5 January 29, 2021.

24. Public Service believes the term "Capacity need" should be omitted because the term is unnecessary and the need for capacity exists in multiple planning contexts (*e.g.*, generation, distribution, and transmission) and across different time horizons. Public Service believes that the term "Demand flexibility" should be removed as it falls under demand response measures. Public Service also states that "Energy storage system" is already defined in Rule 3001(l), and it is a general term that can be used by other rule sections. If the Commission decides to keep this term, then Public Service suggests using the same definition from Rule 3001(l).[12]

25. Public Service notes that the term "Locational value" is highly contextual, as it is typically used to describe benefits that can be provided to the distribution system to meet geographically specific constraints identified in the distribution planning process. Public Service also recommends removing the terms "Pilot," "Program," "Reliability Need," and "Resilience."

26. Public Service suggests minor edits to eliminate some of the ambiguity in the proposed definition of "Hosting capacity." They suggest replacing the word "accommodated" with the more technically accurate term "interconnected." Public Service also clarifies in its proposed edits that hosting capacity only describes these conditions under current and normal system configurations (*e.g.,* not N-1 contingency conditions that may lead to system switching and reconfiguration).[13] Public Service emphasizes that hosting capacity analysis is an initial guide and does not replace the DER engineering screens or system impact screens described in the interconnection rules.

[12] Public Service Initial Comments, p. 15. January 29, 2021.
[13] *Ibid.*, p. 16.

27. Public Service also suggests a clarification as N-1 is a general term applicable to both transmission and distribution system planning and operations that describes the loss or failure of a single system component. Public Service suggests striking the second sentence of the proposed definition as it does not define an N-1 event, but rather may or may not be a potential implication of an N-1 event.[14]

28. Black Hills proposes to add a definition for Critical Electric/Energy Infrastructure Information (CEII) based on that used by the Federal Energy Regulatory Commission (FERC). Upon defining CEII, Black Hills would reference it within other rules as a rationale under which the utility could withhold information from both the DSP filing and the utility web portal. We decline to adopt Black Hills' proposal. The record is insufficient on the impacts of modifying a definition that was developed by FERC for application to the bulk power system to the distribution grid level, especially given that the FERC process relies on managing CEII data releases through an independent central data coordinator, which is not a component of the Commission's rules.[15] While COSSA/SEIA acknowledged that a utility should be allowed to protect CEII, they refer to FERC-defined CEII, rather than Black Hills' Colorado-specific definition.[16] Furthermore, Black Hills' definition is unnecessary. As we discuss below, the Colorado rules do not need to refer specifically to a federal practice to allow regulated utilities to make reasonable protective claims associated with that practice. Should a regulated utility seek to protect FERC-defined CEII, it may do so through the motions process laid out in Rule 3540.

29. We adopt several recommended changes to 3527(c) "Demand Flexibility" for improved clarity and adjust the definition to indicate that demand flexibility often includes

[14] *Ibid.*, p. 16.

[15] https://www.ferc.gov/enforcement-legal/ceii.

[16] COSSA/SEIA Initial Comments p. 44. January 29, 2021.

communication or control technology, rather than in every situation. We adopt clarifying language in 3527(f) "Distributed energy resources," 3527(h) "Energy efficiency measures," 3527(k) "Hosting capacity," and 3527(I) "Locational value."

30. We agree with Public Service that as "Energy storage system" is already defined in Rule 3001(l), it is a general term that can be used by other rule sections.

31. Based on suggestions by Public Service, we delete language regarding office software or hardware language. Public Service argues it is unclear how including these elements in the definition is consistent with the NWA processes in this rule. Public Service argues this language could create confusion as solutions such as Distributed Energy Resource Management Systems are in fact software that could support NWA, not solutions to be avoided through NWA.[17]

32. We also add clarifying language to 3527(p), "Non-Wires Alternative" or "NWA," and delete the redundant term "cost-effective."

a. Rule 3527(a). Ancillary Services

33. We add a definition for "Ancillary services," as the term is used in reference to Rule 3532, Grid Needs Assessment.

b. Rule 3527(e). Direct Current Fast Charger

34. WRA recommends the Commission adopt a new definition within Rule 3527 that would define the term "direct current fast charger" for use elsewhere in the rules.[18] The Joint Stakeholders adopt this proposed new rule in its post-hearing comments.

[17] Public Service Initial Comments p 15. January 29, 2021
[18] WRA Initial Comments, p 5. January 29, 2021

35. We adopt this definition as we expect utilities to identify locations where substation transformers and feeders have sufficient capacity for hosting multiple direct current fast chargers in Rule 3533.

c. Rule 3527(i). Grid Availability

36. The Joint Stakeholders proposed a new definition for "grid availability" to help enable reporting on the availability of the grid as it applies not only to load but also to customer-side resources, such as distributed generation and demand response. They state that the goal of adding this definition, as well as the related reporting requirement in Rule 3531, is to help ensure that the grid remains available as much as possible and customer-side resources do not face unnecessary outages.[19] We agree with this addition.

37. The Joint Stakeholders also propose a new definition for "grid need" to clarify the underpinnings for the required grid needs assessment in Rule 3532.[20] We agree with this addition.

d. Rule 3527(s). Ratable procurement

38. The Joint Stakeholders propose a new definition for "ratable procurement" which they state is the procurement of incremental DER capacity to defer or avoid long-term grid needs. We agree with this addition, as this term is included in Rule 3532 related to the grid needs assessment. We made a minor modification to the proposed definition to clarify that the purpose would be to defer or avoid traditional utility infrastructure, more specifically.

3. Rule 3528. Distribution System Plan Filing Requirements

39. The Commission proposed that the utility file a DSP as an application every two years, with the first plan to be submitted on or before January 31, 2022. Rule 3528(d)(I-IV) was

[19] Joint Stakeholders Post-Hearing Comments, p. 6. April 16, 2021.
[20] *Ibid.*

proposed to allow for flexibility for certain filing requirements that may not yet be practicable or are cost-prohibitive in the early stages of DSP.

40. Several participants recommend changing the date of the first filing in order to allow utilities adequate time to develop their plans, given that the timeline of this proceeding may have exceeded the timeline that was envisioned when the Commission issued the notice of proposed rulemaking.

41. Participants also agreed that a two-phase litigated DSP process is the best path forward for DSP Rules. Under the Joint Stakeholders proposal, the utility will file a "Phase I DSP" as an application, including the components of the DSP filing that are listed in proposed paragraph 3529(a). In the Joint Stakeholders' proposed Rules, Commission Staff, the utility, and any other parties will participate in a litigated proceeding, and the Commission will issue a decision approving, modifying, or denying the Phase I plan. If the Phase I plan identifies Major Distribution Grid Projects that meet the NWA suitability screening criteria and proceed to solicitation, then the utility is required to submit a Phase II filing as described in proposed Rule 3529(b) after completion of the solicitation process. Parties will have the ability to submit two rounds of comments following the Phase II filing, and the Commission will issue a second decision. The Joint Stakeholders have removed the opportunity for limited discovery that was originally proposed in response comments in order to move towards consensus with the utilities. The Joint Stakeholders believe that this framework strikes the appropriate balance between allowing for a comprehensive review and feedback process and achieving procedural efficiency.[21] Public Service proposes additional language to allow for even more flexibility in Rule 3528(c). Public Service explains that it has purchased distribution system planning software and is

[21] Joint Stakeholders Post-Hearing Comments, p. 9. April 16, 2021.

training staff on the use of a more sophisticated load forecasting software program (LoadSEER). Public Service explains that they are currently proactively integrating this more advanced planning software that will ultimately allow it to produce better quality DSPs in future cycles. However, Public Service notes that this software will not be fully implemented in time for the first DSP filing.[22]

42. Black Hills presents language that enables a staggered filing cycle between a large- and smaller-sized utility. We agree with Black Hills and stagger the DSP filings by the size of utilities in 3528(a).

43. The OCC adds additional requirements to the stakeholder process in 3528.

44. The Joint Stakeholders propose a new paragraph in the Consensus Rules, encouraging stakeholder engagement to discuss DSP topics and resolve issues to the extent possible outside the litigated proceeding. The Joint Stakeholders state that proactive stakeholder engagement can increase efficiencies and have accordingly proposed this rule to require at least one meeting prior to the Phase I filing and to encourage further meetings as needed. The Joint Stakeholders also propose that utilities be required to describe how they engage with communities of "historically underserved customers" and how they incorporate goals related to equity in their DSP process.[23] We acknowledge this principle, but suggest clarifying language. We use the term "disproportionately impacted communities" instead of "historically underserved customers." While the term "disproportionately impacted communities" is defined for use by Colorado Department of Public Health and the Environment (CDPHE) at § 25-7-105(1)(e)(III), C.R.S., recent Commission decisions have recognized CDPHE's approach to interpreting this

[22] Public Service Post-Hearing Comments, p. 22. April 16, 2021

[23] Joint Stakeholders' Consensus Rules Att. A p. 5, April 16, 2021.

term, and recently signed SB 21-272 which sets forth a path for the Commission to incorporate it more specifically. Accordingly, we use this term throughout the rules, in the interests of consistency across state agencies and with emerging state policy.

45. We agree with the Joint Stakeholders' recommended language changes to Rules 3528(a) and (b), with their proposed new requirements in 3528(c)(I) and (II), with their proposed new requirement to file a final Action Plan in 3528(e), and language establishing guidelines for the stakeholder process in 3528(g). In addition to language regarding the stakeholder process, we specify that utilities shall make all reasonable efforts to engage local governments and community organizations representing disproportionately impacted communities. We believe that engaging such communities early in the process will result in improved programs and pilot projects with local and impacted community input. Early engagement with disproportionately impacted communities should also allow for the best opportunity for equity and environmental justice to be structurally incorporated in future planning processes.

46. We decline to adopt OCC's additional language as we believe those topics are covered in the modified language proposed by the Joint Stakeholders, and note that the Commission has discretion to require utilities to host stakeholder discussions regarding specific DSP topics.

4. Rule 3529. Contents of the Distribution System Plan.

47. SB 19-236 directed the Commission to determine what must be included in a DSP filing, which at a minimum must include system and substation historical data, peak demand, forecasts of DER adoption, and current distribution investments. Proposed Rule 3529 lists the required contents of each plan.

48. The Joint Stakeholders propose a new subparagraph 3529(a)(III), which requires a description of the utility's vision for how existing utility DSM measures and programs, as well as existing DER offerings, shall or could be utilized to meet DSP needs, in order to integrate existing utility offerings that have been approved by the Commission within the DSP process. They also add a subparagraph 3529(a)(XV), which requires a description of the stakeholder engagement process described in paragraph 3528(f).

49. The Joint Stakeholders also propose subparagraph 3529(a)(XVI), requiring a description of how the utility has engaged, and plans to engage, on DSP with communities, particularly those consisting of historically underserved customers, and how the utility has incorporated community climate, equity, and resilience goals and priorities into the DSP and action plan. Boulder and Denver also propose language to ensure that the DSP process include stakeholder and local government consultation. They believe distribution system planning can support critical community needs such as public safety, natural disaster resilience, and coordination of distribution system work with other community planning and development activities.

50. The OCC also provides redline rules that require utilities to engage stakeholders. The OCC recommends the rules require a utility to preview its upcoming plan with stakeholders and solicit feedback and suggested modifications for incorporation into its upcoming plan. The OCC also proposes that the utility be required to hold specific stakeholder reviews of system forecasting and hosting capacity. At a minimum, the utilities should solicit input from stakeholders on the following topics: (1) the load and DER forecasts; (2) proposed five-year distribution system investments; (3) anticipated capabilities of system investments and customer

benefits derived from proposed actions in the next five years; and (4) any other relevant areas proposed in the DSP.

51. Public Service provides redline edits to Rule 3529 to reflect the conceptually agreed upon Phase I process and included additional redlines to align the rule with the agreed-upon Phase I process.

52. We agree with the recommended language by the utilities and the Joint Stakeholders that add “programs and other electrification” when discussing beneficial electrification. We adopt the Joint Stakeholders’ proposed language in 3529(a)(III) regarding the integration of DSM and other DERs, so that it can be utilized to meet distribution needs. We also adopt the proposed language surrounding the stakeholder process in 3529(a)(XIV) and (IV).

53. For clarity, we also add Rule 3529(a)(XIII), which requires the utilities to submit a proposal for implementation of a web portal as further described in Rule 3541.

5. Rule 3530. Distribution System Forecasts.

54. SB 19-236 requires the utility to provide “a forecast of the growth of distributed energy resources for the years covered by the plan.” The Commission proposed an approach in Rule 3530 using Multiple Load, DER Growth, and NWA scenarios to assess current system capabilities, identify incremental infrastructure requirements, and enable analysis of the locational value of DERs and NWA. All the forecasts would project load ten years into the future, with data to be provided for each year over the ten-year span. We further requested that the utilities provide a reference to the load growth scenario modeled in their latest ERP to allow the Commission to see consistency across proceedings, or to understand if a different scenario is presented.

55. The Joint Stakeholders recommend several modifications in the Consensus Rules related to distribution system forecasts that build off the recommendations made by CEO in its Initial Comments. They agree with the Commission that a DSP should include a forecast of DER growth, but believe that the current rule could be clarified, and they suggest several revisions to paragraph 3530(a) that they believe are consistent with the Commission's intent to provide a forward-looking view of changes that may impact the distribution grid but also clarify the data and information that must be provided in each scenario.

56. In its Post-Hearing Comments, WRA recommends that the rules require utilities to file ten-year forecasts in their DSPs. WRA highlights a nuance within the comments about forecast timeframes in this Proceeding and during the Public Comment Hearing. WRA argues that Public Service's comments that the provision of ten-year forecasts will be of limited use to the Commission due to inherent uncertainty would also lead to avoiding the assessment of potential grid investments in that five- to ten-year timeframe. WRA argues that without ten-year forecasts, it would be impossible to provide a grid needs assessment for a ten-year timeframe, as described in proposed Rule 3532. Consequently, there would be no opportunity to consider pilots or NWAs relevant to grid needs within this period.

57. SunShare notes that the NOPR stated that a key step in the DSP process is to characterize the capabilities and limitations of the existing distribution system, which requires a detailed review of the capacity of existing infrastructure, as well as known problems, limitations, and areas of concern."[24] SunShare states community solar garden (CSG) interconnection has plagued a large percentage of distributed renewable energy development in Colorado approved in RES Plans and this topic represents "known problems, limitations, and areas of concern."

[24] Decision No. C20-0837, at ¶ 77.

SunShare argues that a key step in the DSP process is to characterize the capabilities and limitations of the existing distribution system, which requires a detailed review of the capacity of existing infrastructure, as well as known problems, limitations, and areas of concern. SunShare believes that a utility's DSP should effect a general increase in available CSG interconnection capacity on the distribution system through expanded or new substations, protective equipment to avoid issues to load serving stations, and facilitate visibility into the hosting capacity of the system where that capacity reaches areas conducive to solar development. In addition, they note that the DSP process should include not only major projects such as new substations, but also for installing equipment on existing substations that facilitates both increased rooftop DER as well as CSG, without one (or the last) cost causer having to pay for it.[25]

58. SunShare notes that COSSA/SEIA previously argued that:

> the Commission should require utilities to provide a forecast of any needed additional hosting capacity, including to support clean DER such as community solar that advance state policy goals because ensuring grid adequacy is necessary to enable beneficial electrification and will increase dynamic load management capabilities through the increased installation of the DER that are necessary to better integrate large scale variable renewable resources and to provide other grid services.[26]

SunShare states its proposed language builds on COSSA/SEIA's comments but provides needed specificity to provide direction and notice to utilities of DSP expectations specific to CSGs.

59. We adopt WRA's recommendation to require forecasts for a ten-year planning period. We also adopt several participants' editorial and clarifying changes in 3530(a)(I-VI). While longer planning horizons likely require more speculation in the later years, a shorter time horizon is not likely to provide the sort of holistic, forward-looking approach that is intended

[25] SunShare Reply, pp. 6-7. February 19, 2021.

[26] COSSA/SEIA Opening Comments, p. 16. January 29, 2021.

with the DSP process. We agree with WRA that the ten-year planning period is necessary to provide the intended benefits of the process.

a. Rule 3530(a)(IX). Scenarios.

60. The Joint Stakeholders recommend that the Commission reconsider the scenarios that a utility is required to present. The Joint Stakeholders suggest that the rules require a "State Policy Goal Scenario" that assumes alignment with state policy goals. They recommend one additional scenario labeled "Growth Scenario," which represents growth in the use of DER and beneficial electrification that goes beyond state policy goals. The Joint Stakeholders argue that scenarios could be realized for reasons such as meeting expedited interim utility milestones, satisfying federal targets related to additional or expedited long-term GHG reductions, demand flexibility, distribution reliability, resiliency, or transmission system needs, or market transformation successes such as the transition to zero emission vehicles. The Joint Stakeholders do not propose a third scenario, though its proposed language leaves this option open for utilities.

61. The Joint Stakeholders also recommend a new paragraph 3530(b) requiring the utility to provide all assumptions and methodologies that are inputs into the forecasting scenarios in paragraph 3530(a). This will allow the Commission and stakeholders to subject the scenarios to a full and complete review. In addition, this information will enable stakeholders to propose modifications to assumptions and methodologies, which may bolster the accuracy and utility of a forecasted scenario or scenarios and ultimately further state policy goals.

62. Public Service argues that prudent planning processes include possibilities that explore outcomes on both sides of the "expected" outcome and argue their proposed changes implement such a forecasting process. Public Service argues that many of the data and procedural items required in the proposed "high adoption" scenario are not readily available,

provide marginal benefit, or contain confidential information. Public Service argues that in order to meet the high DER adoption scenario, significant investments into grid-edge infrastructure and technologies may be required. They further argue that if this is to be a proactive deployment, there are challenges associated with determining which customers will adopt the technology and subsequently which assets to upgrade proactively. Public Service concludes that this can lead to overbuilding the system and adding unnecessary costs, which, under the current planning paradigm, would be socialized amongst all customers.

63. We adopt a two-scenario process for forecasting DER and NWA growth, including a business-as-usual case based on current state policy, as well as a High Growth scenario. We agree with CEO, who proposed "State Policy Goal Scenario" that assumes alignment with state policy goals such as GHG reduction targets, EV deployment levels DSM, and RES targets needed to achieve the State's policy goals. One example of a state policy scenario is Governor Polis' Greenhouse Gas Reduction Roadmap (Roadmap) which provides an assumed pathway for achieving Colorado's science-based climate goals, established by House Bill 19-1261. However, state policy goals may evolve over time and each DSP application, along with its scenarios, should take into account the state policy goals in place at the time of the application. We agree with CEO and WRA that the Roadmap's trajectory should be assumed in a business-as-usual scenario. Each forecast must be based on the current state policy goals, including the GHG reduction targets, at the time the forecast is developed. The Commission plays an important role in achievement of the State's statutory climate goals and achievement of these goals is a necessary base assumption for any scenarios that are evaluated. The State's policy goals should be treated as the floor, not the ceiling, for planning of the State's utility infrastructure. This baseline is also important to enable better planning and information-sharing

across proceedings with a foundational set of assumptions aligning strategies and tactics to aid in the pursuit of those goals.

64. We also agree with the Joint Stakeholders' "Growth Scenario" which represents growth in the use of DER and beneficial electrification that goes beyond state policy goals. As they point out in Post-Hearing Comments, this scenario could be realized for reasons such as meeting expedited interim utility milestones, satisfying federal targets related to additional or expedited long-term GHG reductions, demand flexibility, distribution reliability, resiliency, or transmission system needs, or market transformation successes such as the transition to zero emission vehicles.[27] It is reasonable to assume that the cost and accessibility of many key DER technologies may continue to improve and could lead the uptake to exceed the state policy scenarios in speed or depth. It is important for the utilities, Commission, and stakeholders to acknowledge that possibility and understand how those scenarios would impact distribution system planning.

65. We also adopt the Joint Stakeholders' proposed language in 3530(b) that requires utilities to provide all assumptions and methodologies that are inputs into the forecasting scenarios.

6. Rule 3531. Assessment of Existing Distribution System.

66. SB 19-236 requires that a utility's DSP report certain data on its distribution system, including: system and substation historical data, peak demand, adoption of Distributed Energy Resources, and Distribution System Investments. Proposed Rule 3531(a)(I) requires each utility to identify and assess major distribution grid capacity needs by providing a map of

[27] Joint Stakeholders Post-Hearing Comments, p. 21. April 16, 2021.

existing and planned substations within its service territory, as well as tabular information about the current design capacity and performance of each substation and substation transformer. The maps would be made available on the utility's web portal as described in Rule 3541. The assessment should also include the status of advanced metering infrastructure deployment by customer class and updates on meter data management systems.

67. Public Service states that it requests clarification from the Commission on the use cases and functional outcomes that provision of this data will enable. Public Service argues that some of the Rule 3531 information does not exist or requires manually intensive efforts to collect and consolidate, and that there are also potential security concerns with providing detailed mapped data.[28]

68. The Joint Stakeholders recommend amending subparagraph 3531(a)(I)(E) to ensure that the number of available feeder buses and circuit breaker bays are included among the reporting requirements. Because utilities sometimes reserve feeder buses or circuit breaker bays for specific purposes, not all feeder buses or circuit breaker bays that are unused may be treated as available. For example, a utility may reserve certain facilities for future load growth, rejecting applications from distributed generation projects that seek to interconnect at those locations. Providing advance notice to distributed generation developers that locations are not available for their use will help to promote optimal siting, reduce the soft costs of site development, and expedite the interconnection of distributed generation at sites with available feeder buses and circuit breaker bays. Disclosing these details can also increase the Commission's ability to ensure the efficient use of existing grid infrastructure, through increased transparency.

[28] Public Service Initial Comments, p. 32. January 29, 2021

69. The Joint Stakeholders recommend adding a requirement to subparagraph 3531(a)(I)(J) that the utility report the percentage of time that the grid is available to load as well as to customer-sited resources, such as distributed generation and demand response. The Joint Stakeholders believe that disclosing this information regarding total grid availability will shed light on the status of such outages, highlight any trends that may need to be addressed, and help to ensure that the grid is adequately and comparably available across the state in all geographic areas and applicable utility territories.

70. The Joint Stakeholders recommend adding a requirement at subparagraph 3531(a)(I)(K) to report minimum daytime load. They state that this is a commonly used industry measurement that refers to electricity demand from 9 a.m. to 5 p.m. and add that daytime minimum load can be used to help calculate the benefits or limitations of solar photovoltaic (PV) generation in a given geographic area.

71. Finally, the Joint Stakeholders suggest adding a new subparagraph 3531(a)(I)(R), requiring the utility to provide an estimate of flexible demand capacity on the system and historic utilization of those flexibility capabilities. They argue that proactive utilization of demand flexibility will be key to ensuring that new load is added to the system in a way that is "smart from the start," reducing cumulative grid demands and avoiding excessive cost impacts. The Joint Stakeholders believe demand flexibility data may prove particularly valuable when paired with the electric vehicle (EV) and charging infrastructure data listed in Commission proposed subparagraph 3531(a)(I)(O), comparison of these data may reveal opportunities for adding demand flexibility to accommodate EV adoption in certain areas while minimizing grid impacts.

72. We adopt several changes proposed by Public Service and the Joint Stakeholders in 3531(a)(I). We also add new requirements for percentage of grid availability, minimum

daytime load, and estimated demand flexibility capacity proposed by the Joint Stakeholders. We believe that this additional information will allow greater transparency into the current distribution system.

73. We agree that disclosing information regarding total grid availability will shed light on the status of outages, highlight any trends that may need to be addressed, and help to ensure that the grid is adequately and comparably available across the state in all geographic areas and applicable utility territories. The added demand flexibility data may prove particularly valuable when paired with the EV and charging infrastructure data which may reveal opportunities for adding demand flexibility to accommodate EV adoption in certain areas while minimizing grid impacts.

a. Rule 3531(a)(II). Hosting Capacity Analysis.

74. Rule 3531(a)(II) specifies that the utility shall also provide a detailed narrative describing the utility's progress towards providing publicly available, real-time hosting capacity data. This should include discussion on how its HCA currently advances customer-sited DER (in particular, solar PV and electric storage systems), how the utility anticipates the HCA identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which the utility anticipates customer benefit stemming from HCA.

75. Public Service states that due to a lack of available secondary and substation infrastructure mapping, and protection of transmission system data, it is limited to analyzing the distribution feeder system only. Public Service's current tools for processing and calculating hosting capacity data are unable to accurately analyze hosting capacity on a feeder-by-feeder basis, which does not take into account the available capacity or DER on other feeders including

contingency situations due to switching or other load transfer capabilities. Public Service argues that the time and money spent developing and updating hosting capacity analyses will not produce the value that interconnecting customers expect.[29]

76. Black Hills states that it does not have current capabilities to comply with Commission requirements regarding HCAs and asserts that while the proposed rules deliver a strong signal to Black Hills that it should pursue new technologies, this will in turn impose new customer costs. Black Hills encourages the Commission to consider modifying its proposed rules to permit, rather than require, certain technology requirements. Black Hills believes that moving the rules towards permissive requirements will ensure that prudent utility decisions are made based on costs and benefits, rather than prescribed Commission directives.[30] Black Hills proposes language that requires smaller utilities to provide an Excel spreadsheet by feeder of either daily daytime minimum load or, if daytime minimum load is not available, daily peak load with the time granularity specified.

77. COSSA/SEIA argue that the Commission should require substantiation of any utility claims that providing access to data would be too costly, including a comprehensive cost-benefit analysis. COSSA/SEIA believe that in the case of Public Service, certain additional data can be provided quickly at little or no additional cost as Public Service appears to have licensed access to the same ArcGIS mapping system that serves as the HCA platform for both Minnesota and Colorado. COSSA/SEIA note that in Colorado, Public Service has not made available to the public, layered data that exists within the ArcGIS mapping tool. Making that layered information available to the public via an existing, already-licensed tool should be quick

[29] Public Service Initial Comments, p. 33-35. January 29, 2021.

[30] Black Hills Initial Comments p. 5, January 29, 2021

and the utility should incur little if any additional cost. In addition, COSSA/SEIA point out that Public Service has recently begun to use more advanced planning tools like LoadSEER in its Minnesota service territory, which allows for more inputs into forecasting and helps to provide more granular, locational forecasting.[31]

78. We agree with several stakeholders, including WRA and CEO, that the HCA process should evolve over time based on user feedback and a robust stakeholder process. As part of this stakeholder process, utilities should solicit feedback from stakeholders on the topic of HCA, among other topics. We agree with WRA, who argue that stakeholders can offer suggestions about how to improve a utility's HCA and data validation process within the stakeholder process and also as part of the litigated DSP process itself. For its first HCA as a result of this rulemaking, and as further described in the context of Proposed Rule 3541, the utility must include the following data on its HCA map and in downloadable spreadsheet format: Transformer Name, Transformer Absolute Min, Load Tap Changer or Regulator, Feeder Absolute Min, and Network or Radial. These data points match what is currently being required by the Minnesota Public Utilities Commission.[32]

79. We believe a smaller utility such as Black Hills should develop its HCA in a phased approach, as we recognize Black Hills currently does not have software capability to provide hosting capacity maps. We agree with WRA, who points out that one such model for this may be requiring all utilities to participate in exploration and discussion activities, but offering a delayed implementation schedule for service territories where HCA remains uneconomic or infeasible. However, we want to emphasize that we believe working towards

[31] COSSA/SEIA Post-Hearing comments, p. 7. February 19, 2021

[32] Minnesota Public Utilities Commission. Docket No. E-002/M-19-685. Order Accepting Report and Setting Further Requirements, Filed July 31, 2020.

deployment of robust HCA and, in turn, better coordination on the distribution system, should yield long-term savings, rather than net costs, for all utilities. These requirements for smaller utilities are found in proposed Rule 3531(a)(II)(G).

7. Rule 3532. Grid Needs Assessment

80. Proposed Rule 3532, based on WRA's proposed rule, requires a Grid Needs Assessment (GNA) to identify the need for critical capacity additions or NWAs that will be needed for substation transformers and feeders that are forecasted to have insufficient capacity to adequately serve peak load over the ten-year horizon. The utility should present this data in megawatt values in tables, in a logical spreadsheet form and graphically as a map for the purpose of the application. The GNA would also identify locations where substation transformers and feeders have sufficient capacity for hosting multiple EV fast charging stations.

81. Both the Joint Stakeholders and Public Service recommend the Commission eliminate the proposed subparagraphs 3532(d)(III) and (IV). The Joint Stakeholders argue this clarification is needed so that where Major Distribution Grid Projects are screened using the NWA suitability screening criteria in Rule 3534, these projects will not be subject to any criteria related to the NWA cost-benefit methodology. These proposed changes will allow the NWA cost-benefit analysis methodology to be used to evaluate the costs and benefits of the NWA bids from the solicitation process and compare these to the traditional solutions.

82. The Joint Stakeholders also recommend adding a requirement for 3532(d)(V) to identify any long-term grid needs that may be avoided or deferred by ratable procurement, defined as the incremental addition on an annual basis of geographically targeted DER deployments, as recommended by COSSA/SEIA in their Initial Comments. They argue that by identifying grid needs that are long-term in nature, but that can be deferred or avoided by

short-term additions of these types of resources, the utility can reduce costs for ratepayers, promote the beneficial use of demand flexibility and DERs, and resolve long-term needs in an efficient manner before they begin to present reliability concerns.

83. SunShare explains that the purpose of Proposed Rule 3532 is to identify where constraints exist on the distribution system and set a pathway for a more transparent review process so stakeholders can understand where constraints are, what kind of investment is being directed towards addressing those constraints, and whether NWAs can provide a more cost-effective solution to traditional pole-and-wire solutions. SunShare proposes language to have DSP plans explicitly address the issue of matching distribution system capacity to the amount of CSG capacity approved and expected to be interconnected to the distribution system.

84. We agree with the Joint Stakeholders and Public Service that proposed subparagraphs 3532(d)(III) and (IV) should be eliminated for clarifying which projects will be subject to the NWA cost-benefit analysis methodology. We also add the evaluation of vehicle-grid integration opportunities, including vehicle-to-grid, as potential NWA projects in 3532(d)(IV). EV adoption metrics should be coordinated across proceedings, wherever possible. Therefore, it is expected that the potential load and capacity anticipated for EVs by major milestone dates would be coordinated with the Transportation Electrification Plan proceedings and any variation in projections being explained.

85. We also agree with the Joint Stakeholders' proposed addition to 3532(d)(V) regarding ratable procurement. We believe this process has the potential to identify grid needs that are long-term in nature, but can be deferred or avoided or otherwise satisfied by short-term additions of these types of resources. Therefore, the utility can reduce costs for ratepayers, promote the beneficial use of demand flexibility and DERs, and resolve long-term needs for

traditional utility infrastructure in an efficient manner before they begin to present reliability concerns.

86. We agree with SunShare that additional language in 3532(d)(I)(F) will allow the Commission to determine whether the Action Plan requires specific investments that will enable cost-effective and efficient interconnection of expected CSG capacity. We expand upon this concept to more generally also include DER capacity, which may include other DER project types, which are also important in pursuit of State policy goals.

a. Rule 3532(d)(II). Exemptions for Short-Term Planning Needs

87. Public Service proposes a new exception to help utilities maintain the flexibility to address planning needs as they are identified (whether through traditional solutions or NWA) to serve customers in a timely and cost-effective manner. Public Service explains that under its current planning process, it maintains flexibility to address planning needs with solutions and mitigations as early as January of the current planning cycle (approximately three months after the planning cycle begins in September). Public Service argues that the ability to serve new loads expediently could become increasingly important in supporting the State's energy policy goals as the transportation and building sectors become increasingly electrified. Similarly, several pending and future economic development activities that create jobs and associated revenues for the State are dependent upon the timely and cost-effective ability to connect new loads. For new load requests, where customers are seeking new or expanded service within the next 36 months from the date of that request, Public Service requests that the Commission provide an exemption for these projects. Public Service notes that in moving to a litigated Phase I process, which will introduce additional delays for major projects, an exemption becomes increasingly necessary.[33]

[33] Public Service Post-Hearing Comments, pp. 18-20. April 16, 2021.

88. We agree with Public Service and add the modified language regarding exemptions for short-term planning needs in Rule 3532(d)(II). We do add language that specifies that as part of its assessment, the utility must adequately explain why this grid need was not previously identified. It is our goal that utilities have an ability to expeditiously meet needs when necessary, but to balance that with the concept that the regular course should be for grid needs to be identified earlier and to follow the outlined process.

8. Rule 3533. Grid Innovation

89. Proposed Rule 3533 adopts WRA's proposed language with some modifications and additions. Rule 3533 includes a subparagraph on new pilot projects (Rule 3533)(a)(I)(A-J), new proposed programs, updates on existing programs, as well as a discussion of any barriers to deployment of DERs and NWA, including regulatory, economic, and technical barriers. These programs may include a focus on identifying locational benefits of DER, energy storage, and enhancing demand flexibility.

90. The Joint Stakeholders recommend including guidelines related to how third parties may propose pilots or programs to the utility and how this information should be included in the DSP. As COSSA/SEIA explained in opening comments, establishing a process for third parties to propose pilots and programs will strengthen the pool of options and provide avenues for third party innovation. This will also ensure that the utility does not bear the sole burden of pilot and program development. Having multiple market actors providing ideas is very likely to garner more innovative ideas than allowing only monopoly utilities to design such pilots and programs.

91. The Joint Stakeholders recommend an addition to the Commission's proposed subparagraph 3533(a)(III), which encourages utilities to consider whether any existing reporting

obligations would be more appropriately reported in DSP proceedings, and it allows them to centralize their reporting in the first DSP. The Consensus Rules also add an additional subparagraph, which requires that new proposed pilots include a description of how the pilot will provide health, safety, environmental, or financial benefits to underserved communities.

92. Finally, the Joint Stakeholders' Consensus Rules include additional language in paragraph 3533(b) that clarifies NWAs, and pilots may include the use of targeted incentive payments to not only encourage DER adoption in a particular geographic area, but also to optimize the use of existing DERs by customers in specific locations, in order to provide locational value to the system, including through the use of existing DERs.

93. Public Service states that it recognizes the importance of piloting and integrating innovative technologies and solutions where it can be done while ensuring the safe, reliable, and secure operations of the distribution grid. Public Service largely agrees with the proposed rules' approach to piloting and larger program design (which may build upon lessons learned from those pilots) and has suggested only slight modifications.

94. We agree with Public Service's modifications in 3533(a)(I) and (II) that help clarify the role of both pilot and new programs as part of its DSP. We also adopt the Joint Stakeholders' proposed language in 3533(a)(IV) that helps to integrate the development of third-party pilots or programs to be evaluated within a DSP. This language will also improve the transparency of the utility process. The language suggested in proposed subparagraph 3533(a)(III) should help the utilities, stakeholders, and the Commission evaluate the appropriate proceeding for pilots, programs, and projects related to DSPs, which may be initially proposed in other proceedings.

95. We also agree with the Joint Stakeholders' proposed addition in 3533(a)(V). We agree with COSSA/SEIA, who explained in initial comments that establishing a process for third parties to propose pilots and programs will strengthen the pool of options and provide avenues for third party innovation. This will also ensure that the utility does not bear the sole burden of pilot and program development and may likely garner more innovative ideas than allowing only utilities to design such pilots and programs.

9. Rule 3534. NWA Suitability Screening

96. SB 19-236 instructs the Commission to develop a methodology for evaluating the costs and net benefits of using DER as an NWA and to determine a threshold for the size of a new distribution project for when a utility must consider implementation of an NWA. Proposed Rule 3536 requires the utility to identify Major Distribution Grid Projects in the utility's Grid Needs Assessment conducted pursuant to Rule 3532. Such projects would be subject to an NWA Suitability Screening to determine if NWAs may be suitable alternatives to conventional solutions.

97. The Joint Stakeholders propose Consensus Rule 3534 "Non-Wires Alternatives," which is a broader rule designed to consolidate the provisions related to NWAs. The Joint Stakeholders believe that centralizing this information clarifies the rules regarding NWAs. This section includes information on the suitability screening process and criteria, the NWA cost-benefit analysis methodology, NWA bid solicitation and evaluation, and the NWA coordinator role and reporting.

98. Public Service proposes additional language in its proposed rules regarding additional flexibility to preserve reliability, serve economic development needs, or to meet other unforeseen circumstances where an NWA cannot provide the planning constraint. Public Service

also proposes to exclude projects such as wildfire mitigation, relocations, and asset health and renewal projects from suitability screening.

99. We adopt some of the language from both the Joint Stakeholders and Public Service. We believe the modified rule language provides both additional direction and added flexibility for the utilities related to the performance of NWA suitability screening. We add to Public Service's proposed language in 3534(b)(IV), which requires utilities to show why the NWA suitability screening is not possible or could not reasonably result in an alternative to traditional utility infrastructure. Again, it is our intent to balance the needs of the utility with a robust, transparent process for distribution system planning. The NWA suitability screening process is intended to be the typical pathway for investments meeting the criteria and justification would be required to identify why that process cannot or should not be followed in specific instances.

10. Rule 3535. NWA Cost Benefit Analysis

100. SB 19-236 requires the Commission to develop a methodology for evaluating the costs and net benefits of using DER as an NWA. Proposed Rule 3534 directs the utility to provide an assessment of the proposed NWA solution using the cost-benefit analysis (CBA) methodology put forward in the most recent version of the National Standard Practice Manual (NSPM) and specifically include certain costs and benefits. The Proposed Rule is intended to provide flexibility so that the utility may also propose an alternative or adjusted CBA methodology if it concludes that the full costs and benefits of the NWA solution are not being accounted for. We expect the NWA CBA methodology to evolve over time as more experience is gained with the process of evaluating NWA against traditional utility investments

and, accordingly, we expect stakeholders to work together to suggest improvements and provide lessons learned.

101. The Joint Stakeholders provide language to clarify that the utility will submit a proposed CBA methodology within the Phase I DSP. They argue that while the NSPM provides valuable guidance regarding cost-benefit analyses, the framework is not sufficient to be a standalone methodology. The Joint Stakeholders acknowledge that the utility will need to develop a CBA methodology, while maintaining that the methodology should align with the NSPM.

102. The OCC believes the proposed CBA methodology is too limited in scope. First, they argue that a DSP will include a wide variety of distribution investments and opportunities and NWA applications are just one type of investment. OCC also argues that within previous proceedings, the utilities have also suggested that very few of the proposed distribution investments would be of the type for evaluation of NWA and that most distribution investments will fall under the proposed investment (dollar) threshold and therefore will not need to be evaluated for NWA. From the OCC's perspective, CBA is the key component for understanding consumer value in distribution investments. Additionally, OCC argues it is a useful tool in decision-making to identify the proper scope, size, technology, and larger system relevance of investments.[34] As a result, the OCC proposes the addition of a rule to require a comprehensive DSP CBA that looks at individual investments and system investments as a whole to create a full picture of how these plans will support decarbonization.

[34] OCC Initial Comments p. 7, January 19, 2021.

103. Public Service states that it appreciates the flexibility that the Proposed Rule 3535 is intended to provide, and it generally agrees with the framework set forth in the NSPM. However, Public Service argues the NSPM should serve as a guiding set of principles, rather than an exhaustive checklist. Public Service also agrees with the Commission that CBA methodologies will evolve over time as more experience is gained, and new information may become available.[35]

104. We adopt several of Public Service's recommend language additions. As Public Service notes in its Reply Comments, no commission in any other jurisdiction has required utilities to apply externally facing and externally scrutinized CBAs to the entirety of their distribution system capital plans as part of integrated distribution planning proceedings, as doing so would create inefficiencies and add labor costs.[36] We believe that the flexibility provided in Proposed Rule 3535 will allow the utilities and stakeholders to develop robust CBA methodologies over time.

105. We also adopt some of OCC's proposed language in 3535(a)(II) and (IV), that expands the information required for the description of the CBA methodology required to be filed within each DSP. In addition to these clarifications, we reorganize Rule 3535 for greater clarity.

11. Rule 3535. NWA Coordinator

106. The Joint Stakeholders propose that an NWA Coordinator may provide input regarding the CBA methodology. The Joint Stakeholders emphasize that the NWA Coordinator is not intended to have decision-making power that undermines the utilities, as the utilities are

[35] Public Service Initial Comments p. 49, January 19, 2021.

[36] Public Service Reply Comments, p. 39-40, February 19, 2021.

ultimately responsible for the safety and reliability of the grid. Under the Consensus Rules, the utility is able to propose distribution grid investments that differ from the recommendations of the NWA Coordinator, which will be discussed in more detail in Section XI. However, the NWA Coordinator is intended to increase transparency and ensure an impartial review of potential grid investments.

107. The Joint Stakeholders believe that an NWA Coordinator is important to the successful execution of the solicitation process, particularly if the Commission allows the utilities to own or operate NWAs, as proposed by both Public Service and Black Hills. The more proactive role of the NWA Coordinator stands in contrast to the role of a bid monitor as proposed in the NOPR and the role of an Independent Evaluator (IE), which is used in the Colorado ERP process. While a bid monitor or an IE could provide oversight of a solicitation process, these roles would not go far enough to create a fair and impartial process because they would not include conducting the solicitation and performing the cost-benefit analysis for NWAs. The Joint Stakeholders reiterate that the NWA Coordinator has the potential not only to enhance the efficiency and transparency of the DSP process, but also facilitate the successful identification of NWAs that provide net benefits to customers.

108. In its comments, Public Service states that it does not support the Joint Stakeholders' proposed Phase II process which is contingent upon the use of an NWA Coordinator role in the NWA solicitation process. In response, Public Service proposes an alternative Phase II process which includes the use of an IE to ensure an objective and fair process for NWA solicitations. Public Service clarifies that its proposed IE role in the Phase II process includes more oversight than the "bid monitor" role reflected in the Commission's

Proposed Rule 3539(b) and is more analogous to the responsibilities of the IE that has long been part of the ERP solicitation process.

109. Further, Public Service also clarifies from Commissioner Gilman's hearing inquiry that it would not only plan to use an IE for all NWA solicitations that meet the Major Distribution and Transmission Project thresholds and meets the NWA suitability screening criteria, but that the use of the IE would be consistent across all major grid project solicitations, regardless of whether it intends to submit a bid. Public Service envisions that the IE would oversee the request for proposals (RFP) and the bid evaluation process, including the application of the utility's litigated and CBA framework to all bids. Public Service describes the use of an IE in its proposed Rule 3537, the Phase II NWA Solicitation Process.

110. Public Service believes that the role of the IE and an NWA Coordinator are functionally similar—that is, to ensure that all parties are subject to a transparent, fair, and impartial NWA solicitation process. Public Service states that it fully supports these objectives and believes that they can be achieved through use of an IE model which has been tested and proven to be successful in Colorado's well-regarded ERP process. Public Service also notes that the evidentiary process in Phase I offers a full opportunity to work out potentially contentious issues such as the number of NWA opportunities, CBA methodologies, model RFPs, and model contracts. Furthermore, within the specific context of soliciting NWAs, the IE model has proven to be effective in other states like California.

111. Public Service questions the need for a third-party to develop its own CBA methodology given that it has committed to collaboratively developing a CBA framework (which will likely leverage many of the best practices set forth in the NSPM) appropriate for Colorado ahead of the first DSP filing. To the extent that consensus cannot be reached in developing the

CBA prior to Phase I, the litigation and discovery process that it has agreed to in Phase I would allow stakeholders to further help refine the CBA. At the end of a litigated Phase I process, the CBA methodology should be established and the application of it to specific NWA solutions should be straightforward, transparent, and easily judged fair or not by the Commission which will have the benefit of third-party IE oversight of the application of the CBA under Public Service's proposal.

112. Finally, Public Service argues that applying an NWA Coordinator construct which is largely still theoretical today, and certainly not tested within the Colorado regulatory environment is the antithesis of efficiency. COSSA/SEIA argue in their reply comments that allowing the utility to conduct an NWA solicitation and potentially bid into an NWA RFP would foster an "anti-competitive" approach and that removal of the NWA Coordinator would require full litigation in Phase II. Public Service disagrees with this assessment based upon experiences and other observations from the ERP process in Colorado, in which it is also allowed to submit its own bids. In that process, Public Service's observations are affirmed by independent, non-partisan analysis.

113. We do not adopt the proposed language that established the role of an NWA Coordinator as described by the Joint Stakeholders. We believe that regardless of terminology and structure, the intended role of the IE, Bid Monitor, or NWA Coordinator is to ensure that all parties are subject to a transparent, fair, and impartial NWA solicitation process. As Public Service points out, these objectives can likely be achieved through use of an IE model which has been tested and proven to be successful in Colorado's ERP process. We also agree with Public Service that with their commitment to collaboratively developing a CBA methodology, there is not a necessary role for a third-party to develop its own CBA methodology at this stage in the

process. If the development of a CBA methodology through the stakeholder process does not result in a satisfactory outcome to participants or if there are substantial concerns about the fairness of the evaluation, the Commission may need to expand or revise the role of the neutral third-party in these areas in the future.

114. We are also cognizant that Public Service's proposed IE has more responsibility and oversight than what the Commission initially proposed with its Bid Monitor role. We acknowledge that Public Service proposes to not only use an IE for all NWA solicitations that meet the Major Distribution and Transmission Project thresholds and meets the NWA suitability screening criteria, but that the use of the IE would also be consistent across all major grid project solicitations—regardless of whether Public Service intends to submit a bid. As proposed by Public Service and adopted in this Decision, the IE will oversee the RFP and the bid evaluation process, including the application of the utility's litigated CBA framework to all bids.

12. Rule 3536. Action Plan

115. Proposed Rule 3536 requires the utility to provide a five-year Action Plan for distribution system investments and activities, including the plans for soliciting the deployment of DERs, as well as plans for permitting, constructing, preparing required reports, and other significant activities where replacement, upgrades, or expansion of utility infrastructure has been identified as the best option.

116. The Joint Stakeholders recommend separating the Action Plan rule into two parts to reflect how the Action Plan will be incorporated into Phase I and Phase II differently. The rule clarifies that the Action Plan in Phase I is not intended to include information regarding NWA that have not yet been solicited. The Phase I Action Plan will include the sequence of events and timelines for each action that will not require a solicitation process following Phase I, including

the implementation of proposed pilots and programs; the construction of conventional solutions to Major Distribution Grid Projects that were determined to be the best option to address grid needs.

117. The Joint Stakeholders Consensus Rules propose a new paragraph 3535(c) that describes the purpose of the Action Plan in Phase II. The Phase II Action Plan will include the sequence of events and timelines for NWAs identified in the solicitation process, including: the implementation of NWAs identified through the NWA analysis process; an updated system interoperability and communications strategy; costs and plans associated with obtaining data necessary for the evaluation of NWAs; and interaction of planned or proposed NWA investments with other utility programs and the effects on existing utility programs and tariffs. The Phase II Action Plan will be the final Action Plan that can be used as a reference for the Commission and stakeholders as the DSP is implemented.

118. SunShare submits that each RES Plan may create a need to expand the distribution system to accommodate CSG interconnection. In such cases, SunShare argues that an Action Plan must include provisions regarding the planned build-out to accommodate more community solar capacity. SunShare believes that if Action Plans create new points of interconnection in line with best available sites for CSGs, it will result in increased certainty to developers, improve the CSG development pipeline for customers and public policy goals, and lead to decreased prices for CSG customers. SunShare proposes that 3536(b)(VII) be explicit in directing where the DSP must address the long-term strategy for deployment of CSG capacity.

119. COSSA/SEIA suggest that the Commission add a requirement under Rule 3535 that the utility identify a strategy to ensure adequate hosting capacity is available for DER,

including identifying any potential NWA or grid updates that may be necessary to ensure such hosting capacity in order to ensure that access to DER is not constrained by hosting limitations.

120. Public Service maintains that its Action Plan application will be a central focus of the overall DSP effort and represents the actions that the utility is planning to take to address capacity needs and Major Distribution Grid Projects, whether through traditional utility upgrades or NWA. Public Service modifies the proposed rules to ensure that the Action Plan will also include proposed pilots and programs.

121. We adopt the Joint Stakeholder proposed language in 3536(c) that requires an updated Action Plan within the Phase II process. We believe the modified rule language clarifies the sequence of events and timelines for NWA, as well as the implementation of proposed projects, pilots, and programs.

122. We also adopt SunShare's recommended rule language in 3536(b)(VII) with a minor addition to refer to all DER, not only CSGs. We believe that it will be vital for additional hosting capacity to be consistent with state policy for clean energy. This language will allow the utility to identify a strategy to ensure adequate hosting capacity is available for DER, including CSGs, including identifying any potential NWA or grid updates that may be necessary to ensure such hosting capacity, in order to prevent hosting limitations from constraining access to DER and CSGs.

13. Rule 3537. NWA Solicitation Process (Phase II)

123. Public Service proposes a new section to Rule 3537, which describes the Phase II NWA Solicitation process. Public Service expects to reflect NWA selections from the solicitation process in an updated Action Plan as per it's Proposed Rule 3537(e), and allow stakeholders to file comments on the final contracts in a non-litigated fashion. This process would be similar to

how electric generation resource selections are reflected in the 120-day report during the ERP process. Similarly, Public Service envisions the proposed IE would publish a report within approximately 30 days, with a follow-on stakeholder review and comment period of 15 days. The process would offer the same benefits that it does in the ERP – namely that bidders can bid into an opportunity with thorough information in place from the just-litigated Phase I process, and also that the bidding process is not itself entangled in lengthy litigation so that successful bids can be implemented in a reasonable timeframe. In this way, this process gives bidders an ideal platform to confidently submit competitive bids.

124. We believe that Public Services' proposed Rule 3537 is a more appropriate path forward for the Phase II DSP process than the Joint Stakeholders' proposed NWA Bid Solicitation and Evaluation process. First, we agree that the Commission's current ERP process should serve as a model for the DSP bid evaluation. We agree with Public Service, which points out that there are many parallels between the all-source ERP process and the technology-neutral solicitation process for NWAs pursuant to the proposed rules. Public Service notes that with regard to objective evaluation of NWA bids, the Commission rules for retaining an IE in the ERP process were created to ensure oversight and result in a fair process. IEs in the past have conducted processes with high integrity and there have been no formal allegations that the resulting processes have not been fair. We agree that in these initial stages of the DSP process, there is no reason to believe that a similar IE role and process could not be successfully applied within the context for NWA.

14. Rule 3538. Approvals and Cost Recovery

125. Proposed Rule 3537 is based upon the proposed rules filed by Public Service, WRA, and CEO. We agree with Public Service that a utility may seek any necessary approvals

for an NWA or pilot through other proceedings such as DSM, RES, TEP, or other appropriate regulatory mechanisms.

126. Public Service agrees with the Commission's inclusion of flexible cost recovery provisions as reflected in the Commission's Proposed Rule 3537. Public Service states it appreciates the diversity of mechanisms for cost recovery that are available to utilities including the use of performance incentive mechanisms (PIMs), creation of regulatory assets, and return on regulatory assets. Public Service also agrees that there are numerous synergies between the DSP process and other proceedings, and the proposed rule recognizes the potential linkages to RES, TEP, and DSM planning processes. Public Service agrees that there are efficiencies and benefits which can be realized by aligning DSP to these proceedings.

127. WRA argues in its Initial Comments that filing for approval of NWAs outside of the DSP proceeding presents several process-related issues: (1) it leads to a lack of centralized information on grid-related projects, effectively reducing transparency; (2) it obscures the funding source for the project; and (3) it may introduce confusion regarding the CBAs and PIMs for NWAs, which will likely be different than those applied to projects in DSM, RES, or TEP proceedings.

128. The CEC states that WRA claims that a "catchall" provision in § 40-2-132(1)(e)(X), C.R.S., "any other information that the commission deems relevant"[37] justifies including Proposed Rules 3537(e) and 3537(f), which would permit utilities to propose placing certain investments into a regulatory asset upon which the utility can earn a return. CEC disagrees with WRA's argument and urges the Commission to revise these rules to comply with

[37] § 40-2-132, C.R.S.

the plain language of SB 19-236. CEC argues that its revisions align the language with the DSP statute, while preserving an intended and critical ratepayer protection – that only costs outside the ordinary course of business should be eligible for non-traditional ratemaking treatment, rather than afford non-traditional ratemaking treatment in an overbroad manner.

129. The Joint Stakeholders also propose removing the language in the Commission's proposed Rule 3537(a) that allows utilities to seek Commission approval for NWAs or pilots in a variety of different proceedings. Having NWA and pilot approvals spread out across multiple proceedings will lead to unnecessary confusion, duplication of effort, and inefficiency. The Joint Stakeholders recommend that funding for NWAs come from traditional distribution grid capital budgets, and not other program funds. As previously explained by several participants in Proceeding No. 19M-0670E and the instant Proceeding, NWAs should be paid for in the same way as conventional distribution grid upgrades, not out of DSM, RES, or TEP budgets. The Joint Stakeholders argue that keeping these budgets separate will ensure that DSM, RES, and TEP budgets are not inadvertently diverted to NWA projects, thereby monopolizing limited funding for those efforts and potentially undermining the aim to provide equitable access to DSM, RES, and TEP programs to all utility customers, regardless of their geographic location.

130. We adopt several modifications to what is now proposed Rule 3538 proposed by the Joint Stakeholders and Public Service, and make several modifications on our own. We disagree with the Joint Stakeholders that the Commission should not allow approvals for an NWA, pilot, or program in other existing proceedings. The Commission and stakeholders will continue to have to grapple with the increasing interrelationship between different proceeding types and we feel it is premature to preclude other options for approval and cost recovery at this time.

131. The Commission is interested in seeing a significant effort by the utilities in NWA implementation. Approaches to serve grid needs that limit expenses and work towards the State's energy policy goals are widely supported and a broader approach to cost recovery may allow for that to happen more quickly and thoroughly. We believe this more inclusive approach allows for more flexible timing and potentially quicker recovery, further encouraging the utilities to pursue these alternative options, where they may provide sufficient benefits to the system and/or ratepayers. While we understand concerns about a decentralization of DSP efforts, allowing too little flexibility may limit adoption by limiting avenues for application and review of potential DSP projects, thereby inhibiting efficiencies we are trying to build.

132. To the extent that expenditures, programs, or pilots have a shared benefit with another program objective, the allocation of the expenses should be allowed to be considered in the appropriate proceeding without our prejudgment in this rulemaking of where an interrelated issue should best fit. Each specific instance should have its approval and costs allocated based on what is the most logical with the facts of that proceeding, as it occurs. Finally, we are sympathetic to the Joint Stakeholders' concerns about ensuring other program areas are not adversely impacted and, therefore, we added clarification in this area. The prospect of funding for NWA solutions through another program area should not adversely impact the opportunity for equal access to those programs nor compromise the goals of those programs.

133. In the end, cost recovery should only be provided through one of the mentioned programs or riders if there is sufficient evidence that the expenditure is aligned with and beneficial to the overall objectives and strategy within that program, but allowing the flexibility for that to potentially occur may allow us to see more successful outcomes in our quest to serve all ratepayers and stakeholders optimally in pursuit of the State's clean energy goals.

15. Rule 3539. Security Assessment

134. SB 19-236 requires utilities to provide a high-level summary of their planning process for addressing cyber and physical security risks. The bill also provides that the utility need not report any confidential, proprietary, or other information in the plan. Proposed Rule 3538 requires the utility to provide a narrative assessment of the reliability and resilience of the distribution grid with respect to cybersecurity and physical security. This information should include the status of distribution grid reliability and plans for improving reliability, including areas of the grid where reliability problems have been identified. A list of major outages involving 10,000 customers or more for each year for the past three years should be compiled. An analysis of cybersecurity issues or other threats to the distribution system and what efforts the utility is taking to ensure the distribution system is secure, as well as risks posed by natural disasters, should be conducted. Finally, the utility should describe any plans, pilots, or programs aimed at increasing reliability and resiliency, through the use of microgrids or other technology.

135. Public Service states that third-party access to some distribution grid data is in the public interest because it can facilitate the development of DERs or increase the transparency of a utility's electric service to customers. Public Service supports providing access to this information to the extent it is reasonable, tied to specific use cases, and provided in a manner that does not compromise the security of the physical assets and systems. In the redline suggestions, Public Service deletes Proposed Rule 3538(a)(I).

136. We make minor changes to what is now Proposed Rule 3539(a)(II) and (IV). We do not adopt Public Service's proposal to delete 3538(a)(I) as it did not provide justification for its deletion in its filed comments.

16. Data Access and Protection

137. Many participants raised concerns regarding what data should be accessible to stakeholders, and under what conditions a utility should be able to protect certain data. While participants generally agree that a successful DSP process will involve significant amounts of data and greater transparency than has previously been available regarding electric distribution systems, they generally disagree over the specifics. Prior to addressing amendments to the rules, we consider participants' broader comments and our overarching expectations for the DSP process.

a. Participants' Comments on Data Issues

138. Non-utility participants argue that electric utilities should be required to provide significant data transparently to achieve DSP objectives. COSSA/SEIA presented numerous benefits associated with improved data accessibility, including streamlined interconnection of DERs; development of locational price signals for DERs; reduced DER siting and planning costs and better use of developers' time; efficient use of grid infrastructure; and achievement of State policy goals related to GHG reductions.[38] OCC believes that data availability is in the public interest and will lead to customer benefits, innovation, and creative solutions to public policy goals.[39]

139. Participants recognize that utilities may need to implement protections related to privacy, confidentiality, or physical/cybersecurity, but they express concerns that these protections should not be overly broad such that they impede achievement of DSP objectives. The OCC, for example, opposes leaving too much discretion to utilities as it relates to data, and

[38] COSSA/SEIA Post-Hearing Comments, p. 4, April 16, 2021.
[39] OCC Initial Comments, p. 21, January 29, 2021.

recommends that the Commission set terms for making data available and invite broader inquiry related to data access, particularly to anonymized data.[40]

140. COSSA/SEIA argue that the Commission should require utilities to provide any information that is not protected by FERC regulations as CEII.[41] They state that utilities in Minnesota, California, New York, and Washington, D.C., are required to produce data in usable formats. COSSA/SEIA argue that "genuine" confidentiality and security concerns can be addressed through practices like aggregation and anonymization of data, and should not lead to blanket exclusions. They suggest that utilities overgeneralize their concerns, and the Commission should require "meaningful substantiation" of attempts to exclude data.[42] To be useful to DER developers—who may otherwise have to make guesses about site viability and even secure access to multiple sites—COSSA/SEIA recommend that data should be geographic, centralized, updated, specific, and interactive.

141. WRA further states that data for feeders or feeder sections serving only one customer should not be revealed, but that the locations of substations and main feeder trunks can be identified through Google Earth and other software tools. WRA argues that the Commission should not allow the utility to use arguments about feeders serving few customers "to exclude information that is needed to make the DSP effective."[43]

142. Public Service's Initial Comments and attachments raise concerns regarding physical security and cybersecurity that it argues are connected to the availability of DSP data. It thus proposes a risk-benefit framework that would weigh the importance of the data to the public

[40] OCC Initial Comments, pp. 21-22 January 29, 2021.
[41] COSSA/SEIA Initial Comments, p 44, January 29, 2021.
[42] COSSA/SEIA Reply Comments, pp. 6-7, February 19, 2021.
[43] WRA Initial Comments, pp. 28 and 41, January 29, 2021.

interest against the consequences of potential misuse.[44] It draws on its internal information lifecycle management policy to propose three categories for treatment of data with increasing protections based on an assessment of their risk: Unrestricted (or Public), Confidential Information (CI), and Confidential Restricted Information (CRI).[45] It further categorizes proposed data requirements from the Commission's NOPR based on these concepts.[46] Public Service acknowledges that it must provide more data as part of the DSP process, but it does question the usefulness of some of the data that the DSP Rules would require it to produce, and it considers significant amounts of data risky from a security or privacy perspective, particularly when mapped and reproduced on its website.

143. In Post-Hearing Comments, Public Service more specifically recommends what protective practices it suggests be applied to Public, CI, and CRI data tiers. However, it calls these recommendations "illustrative" and states that it reserves the right to request the Commission to further limit disclosure through other mediums, such as secure and encrypted email. It suggests non-disclosure agreements (NDAs) and usernames and passwords be required to access CI, and that a background check may be appropriate for access to CRI. Subsequently, Public Service characterized its proposal as an effort to engage stakeholders in a productive, consensus-oriented discussion, and clarified that it does not intend to withhold data.[47]

144. In Initial Comments, Black Hills stated that it is premature to advise on which specific data or metrics have the greatest privacy risks or may include proprietary information. It recommended a workshop on data and information security and proposed that the Commission

[44] Public Service Initial Comments, Attachment D, p. 22, January 29, 2021.

[45] Public Service Initial Comments, Attachment C, pp. 8-9, January 29, 2021.

[46] *See generally* Public Service, Supplemental Attachment B, February 2, 2021.

[47] Public Service Supplemental Comments, p. 4 May 7, 2021.

consider a rulemaking on protecting critical energy infrastructure.[48] Black Hills subsequently indicated support for Public Service's proposals related to data privacy, confidentiality, and security, and its closing comments recommended that the Commission incorporate a definition of CEII like that used by the FERC within the rules. Black Hills suggested that this would help the Commission avoid "unnecessary disputes" around what information should be public in DSP filings.[49]

b. Treatment of Data in DSP Processes

145. DSP processes will involve the collection and production of new and granular data, both spatially and temporally. In particular, geospatial mapping may allow new insights and innovation but also create new challenges to important values like privacy, confidentiality, and security. As such, DSP processes should continue to emphasize how to reach a thoughtful balance among these areas.

146. We believe utilities have overstated or confused some of the issues associated with the data that the DSP process will require. For example, Public Service shares its fear of cyber-attacks perpetrated by foreign nations that can result in direct manipulation of its corporate information technology systems. Without at all diminishing this valid and significant concern, this issue is not analogous to providing information to DER developers that they can use to improve the value that their systems provide to the overall distribution grid. While we appreciate Public Service's concerns related to physical and cybersecurity, and recognize their criticality as a component of providing safe and reliable service, we believe there are many ways these concerns can be managed while still achieving the goals of the DSP process. Public Service

[48] Black Hills Initial Comments, p. 15, January 29, 2021.
[49] Black Hills Post-Hearing Comments, pp. 6-8, April 16, 2021.

declined to provide any kind of specific analysis related to data requirements in the prior two years of stakeholder engagement that led up to this Proceeding, despite frequent discussions as to potential data needs. Furthermore, utility participants sometimes cite broad concerns that are unrelated to the specific issues at hand or provide too little support for their concerns to be properly vetted.

147. At the same time, we lack robust information in this record to assess the trade-offs associated with directing specifically how data should be presented and protected, both in the DSP Application pursuant to Proposed Rule 3540, and in the Web Portal pursuant to Proposed Rule 3541. For their part, the utilities have real concerns about the cyber and physical risks to the system associated with releasing detailed information. Since these risks are nearly all prospective, and are sometimes highly speculative, it is hard to understand their potential severity and how to compare that with the potential benefits of the data being more accessible and usable. Conversely, while other participants support significant increases to data availability, it is not clear if they have been selective in the information they are seeking, particularly in being specific about information that is useful and not beyond the granularity or frequency that is necessary to meet the objectives of DSP. Regardless of whether data is sensitive, if its value in achieving the objectives of the DSP process is unclear or extremely limited, then the merits of its inclusion should be questioned in more depth.

148. The decision before the Commission is not black-and-white, such that all data should be decreed public, or that there is a particular standard that is appropriate for managing such diverse concerns as privacy, security, and confidentiality, regardless of whether information is in a PDF, in E-Filings, or on a periodically refreshed mapping website. That is not the reality of data management, and such decisions are difficult to make in the abstract, without the

Commission having litigated a DSP proceeding yet and without seeing the data in question. Prescriptive statistical practices set forth in rules are likely to be insufficiently flexible to manage a large and growing amount of data, especially in a field that is rapidly evolving. The DSP process should not remove utilities' existing obligations to protect personal information and customer data, but it should require them to apply more thoughtful and balanced practices. These practices may vary depending on a variety of factors, including the granularity of data, the frequency of updates to data, whether data is presented in tabular or geospatial format, and which data points are presented together. De-identified (*i.e.*, anonymized) data may be appropriate for some use cases, heat maps for others, release of statistical properties but not exact data for others, aggregation to particular geographies for others, and actual data that is protected to verified users for others.

149. Accordingly, we believe that DSP objectives can best be met where we craft a process that allows utilities to recommend data protections based on meaningful engagement with stakeholders, with the Commission resolving disputes based on a complete and specific record. We do not have a complete or specific record here upon which to do so. We thus amend the rules to coordinate the development of the web portal with each utility's first DSP application. This will create consistency in how data is treated and updated between the application and the web portal; allow for clearer discussions related to data treatment and protection; and enable the Commission to assess the web portal's use and usability over time to reflect the dynamic nature of the data that may be necessary to meet the DSP objectives.

150. The web portal developed under Proposed Rule 3541 is anticipated to be dynamic, with the ability to navigate geospatially, view layers, and present information associated with elements like substations or feeders, among other features. To implement

appropriate protections for this data, we must understand its potential uses, what granularity and specificity is needed to achieve those uses, whether that data is actually or potentially sensitive (alone or in combination with other relevant data), and whether there are protections that enable its release that are appropriate with consideration to its usefulness and sensitivity. This record must be developed by engaging potential users of the web portal. Accordingly, the amended rule requires utilities to engage potential users to develop a proposal for implementation that includes use cases that achieve DSP objectives. The engagement should occur both before and during the DSP filing itself to come to consensus wherever possible and to bring more detailed information about the risks and benefits associated with each data point into the upcoming DSP proceedings, to allow the Commission to make a determination about the proper treatment of the data within the web portal.

151. In subsequent DSP filings, utilities should also engage in an upfront process with web portal users and stakeholders to identify any updates needed to the web portal, including any changes to the inclusion or treatment of data. This process should allow for appropriate stakeholder input in the evolution of the web portal to ensure it is properly serving its purpose, even as we may see the data or means to serve that purpose adapt over time.

17. Rule 3540. Data Access, Privacy, and Confidentiality

152. Proposed Rule 3540 addresses the treatment of data within the DSP Rules. Upon consideration of parties' comments and a review of the Commission's existing processes as they may be applied to the DSP Rules, we find that Proposed Rule 3540 should be refined. An overarching concept is that Proposed Rule 3540 should now apply clearly to both DSP applications pursuant to Proposed Rule 3529, and to web portals developed pursuant to

Proposed Rule 3541, unless otherwise specified, to better align the discussion of data treatment in the web portal with the DSP application process.

153. First, we title the Proposed Rule "Data Access, Privacy, and Confidentiality." We adopt "access" as proposed by COSSA/SEIA because facilitating reasonable access to data is a priority for the DSP process.[50] We do not believe it is necessary to add the term "Security" to the title as proposed by Public Service to authorize utilities to make claims regarding the potential sensitivity of data based on physical or cybersecurity considerations.[51] Furthermore, "data security" has connotations of information technology issues that are not intended to be addressed by this Proposed Rule. Since the Commission has existing rules related to privacy and confidentiality that are referenced in Proposed Rule 3540, we retain those terms in the rule title.

154. Proposed paragraph (a) clarifies that utilities subject to the DSP Rules shall disclose data necessary to implement these rules, with consideration toward sensitivity and public benefit. It thus incorporates language proposed by Public Service and recognizes that a utility may apply a risk-benefit framework for evaluating data protection and release. Such a change is reflective of the Commission's evolving perspective around data access, which must be more dynamic and must continue to transition away from binary views on data treatment. We further find that it is not necessary to retain a presumption that data in a DSP application be considered non-confidential, as that is the Commission's existing practice in the absence of protections sought by utilities or specific rules related to confidentiality and privacy.

155. Proposed paragraph (a) also clarifies that as utilities identify sensitive information and address how it will be treated both in the DSP application and in the web portal, they must

[50] COSSA/SEIA Initial Comments, p. 44, January 29, 2021.
[51] Public Service Closing Comments, p. 24, April 16, 2021.

consider the overall objectives of the DSP process. Given the diversity of options we previously described for balancing data access with data protections, we will be taking a careful look at proposals for treatment of data in the DSP application or in the web portal that withhold or obfuscate data to the degree that they impede the objectives of DSP.

156. Proposed paragraph (b) confirms that utilities have a continuing obligation to protect certain types of data, including personal information (*e.g.*, customer names or payment information) and customer data (*e.g.*, energy usage). The NOPR proposal waived Rules 3025 through 3035 in their entirety. Both Public Service and Black Hills raised concerns that this broad waiver was inappropriate for the DSP Rules. We agree, but only in part, and we retain a specific waiver as to the applicability of Rule 3033(b). Much of the data being provided through the DSP process is likely to be considered "aggregated," thus invoking the "15/15 Rule." We do not believe this is an appropriate default practice, as it may be overly protective in some settings and insufficiently protective in others.

157. Consistent with the discussion above, in adopting this waiver, we decline to prescribe specific statistical practices that were developed years prior to the implementation of the DSP process. We both lack information indicating that the 15/15 Rule is appropriate for the data the DSP process requires, and suspect that there will be a variety of practices that may be appropriate that both meaningfully protect customer data and allow for the objectives of DSP to be met. Should future DSP proceedings reveal that our existing rules related to data privacy and confidentiality are inappropriately calibrated to balancing reasonable access and reasonable protections for customers such that they impede achievement of critical state energy policies, we may find it necessary to revise them.

158. Proposed paragraph (c) specifically addresses the filing of a DSP application pursuant to Proposed Rule 3529. Participants expressed general support for using the Commission's existing motions process under Rule 1101 of the Rules of Practice and Procedure to address concerns related to data confidentiality.[52] In our revision, we borrow language from Rule 3604(j), on ERPs. As with ERPs, we anticipate that DSP proceedings will involve a significant amount of data, but it is unclear at this stage how extensive claims related to confidential or highly confidential treatment may be. As modified, this paragraph would require utilities to provide a list of information claimed to be both confidential and highly confidential, to facilitate a more streamlined consideration of appropriate treatment in DSP proceedings. As we previously stated, a claim related to CEII status could be made under this provision, regardless of express direction.

159. Finally, we address proposals from Public Service related to access provisions, which were made in response to prior paragraph (c), as part of Proposed Rule 3541 to reduce duplication.

18. Rule 3541. Web Portal

160. Proposed Rule 3541 directs the utility to develop a web portal with stakeholders that will help achieve the objectives of the DSP process. The web portal is intended to foster transparency, clarity, and convenience for stakeholders. As Public Service has stated in this and prior proceedings related to DSP, it has many different policies, programs, and reporting requirements related to the distribution grid. There has not been any effort to provide this large amount of information into a single, secure source where energy consumers and other stakeholders can benefit.

[52] *See, e.g.*, WRA Closing Comments, p. 9, April 16, 2021.

161. We propose significant changes to the original web portal rule based on participants' comments throughout this Proceeding. The web portal would be the main means by which the public and many stakeholders could access distribution system information. As such, this has been an area of contention, with the utilities arguing to keep more information confidential (or potentially protected in some way) and the other parties stressing the importance of as much transparency in the data as possible.

162. As a foundational concept, we believe that the DSP web portal should be designed to help regulated utilities and stakeholders achieve the objectives of the DSP process. Proposed Rule 3526 and this Decision lay out objectives for the DSP process that include evaluating a utility's investments in the distribution grid, diversifying energy supply through DERs, and preparing for changing expectations as they relate to distribution technologies and customers. The web portal could have many applications within this context, but we believe that at least four objectives emerge from participants' comments, and reflect our priorities for this rule:

- The web portal should enable DER developers to optimize the selection of sites and design of systems that will deliver value to the grid, thus promoting a more transparent interconnection process;
- The web portal should enable the acquisition and deployment of cost-effective NWAs;
- The web portal should enable customers and communities to understand how utilities are progressing toward achieving state energy policy goals; and
- The web portal should enable customers and service providers to quickly and easily identify what programs, incentives, and/or tariffs are available to allow them to participate in the deployment of DERs.

163. To achieve these objectives and to manage information technology costs and expectations, utilities must engage stakeholders and potential users in detailed workshops or stakeholder processes about the web portal functionalities and usefulness. While there was often

agreement among participants regarding what information should be placed on the web portal, we believe that incorporating highly prescriptive rule requirements related to specific metrics could result in unnecessary expense and lock-in design rather than allowing it to move with technology and evolve with use cases. Accordingly, our revision to the rule focuses less on specific metrics that must be produced, and more on establishing a process by which a web portal can be proposed, approved, evaluated, and updated as needs and software capabilities evolve—always with a focus on engaging users and fulfilling the objectives of DSP.

a. Terminology

164. The NOPR used the term "web portal" to convey that the intention is to centralize relevant data and provide jumping-off points for more information. Public Service proposes to replace "portal" with "site" as it states that portal conveys two-way access, whereas it would not be providing users with access to its systems and databases.[53] We agree with Public Service that the intent is not to provide users with access to a utility's systems and databases. However, we retain the term "web portal" to convey that the tool created pursuant to Proposed Rule 3541 may be a central hub for information that may include log-in access for some elements.

b. Rule 3541(b). Access Restrictions

165. Public Service expresses concern that the current rule language does not allow it to control access to its website or reduce the risk of anonymous use, given the security concerns it has mentioned. It argues that full public disclosure of grid data is risky and that by providing and maintaining up-to-date maps of asset and feeder locations, load data, and electrical connectivity in a single, integrated, and unprotected venue like a hosting capacity or load map—electric utilities are effectively "connecting the dots" for bad actors, making it easier to

[53] Initial Comments of Public Service Company of Colorado (January 29, 2021) at p. 62.

plan coordinated attacks. Public Service states it is not suggesting that it prohibit the disclosure of data which may provide public benefit. However, appropriate safeguards and protocols must be implemented to minimize the opportunity for bad actors to leverage data for nefarious purposes. Accordingly, Public Service needs to maintain the right to monitor and mediate access to critical grid information.

166. Public Service recommends changes to rule language that would allow it to apply the following practices at its discretion, based on whether it classifies data as Public, CI, or CRI:

a) Requiring all users to acknowledge terms of service;

b) Requiring users seeking certain kinds of data to register and create a username and password;

c) Requiring users seeking certain kinds of data to sign an NDA; and/or

d) Requiring users seeking certain kinds of data to pass a background check.

167. Public Service does not describe how an NDA would be developed or applied. It states that two utilities, PSEG-LI and SDG&E, require a background check to access online maps, and it provides a link to the PSEG-LI process which implies that the CLEAR check is typically completed within 24 hours.[54] Public Service provides an illustrative table in which access to information that is designated CRI would require a background check. This could include data like class coincident peak, substation maps, SCADA capabilities, NWA suitability, and historic and projected capital budgets.[55]

168. COSSA/SEIA originally opposed registration processes, but in supplemental comments, they amended this position to clarify that they are not opposed to registration that is

[54] Closing Comments of Public Service Company of Colorado (April 16, 2021) at 26: (https://www.psegliny.com/aboutpseglongisland/ratesandtariffs/sgip/-/media/C6B9654A4B01497F860AE7BE086EE2FB.ashx).

[55] *See generally* Public Service, Supplemental Attachment B, February 2, 2021.

designed to reduce anonymity and enable appropriate access to information rather than to preclude access. COSSA/SEIA note that two-factor authentication or similar practices may be appropriate and do not specifically mention background checks or NDAs. In initial comments, Boulder similarly proposed that there be a public dataset with less transparency and a dataset with "limited availability and greater protection for those that desire to take a deeper dive."[56]

169. Public Service characterizes the issue before the Commission as follows: "Before the Commission is a determination of whether less information should be provided on the utility website in order to maximize availability to the public or whether the utility decides who has access to the website."[57] This as an oversimplification, given the array of options for data treatment that we previously discussed. The proposed web portal would require Public Service to centralize and update information about the distribution grid and DERs. Website terms of use and registration processes—which may require creating an account with a username and password, as well as two-factor or multifactor authentication—are reasonable precautionary steps that utilities may implement to prevent fully anonymous use of such information for which there is at least some reasonable risk of misuse. The third parties that are contemplated to use the Rule 3541 web portal to access more detailed system information, such as DER developers, NWA bidders, state or local agencies, and academics, should not have difficulty with the proposed registration requirements. Locational information about distribution infrastructure and DERs is often publicly available through websites like Google Maps, but that does not mean that all distribution grid data needs to be available without any restrictions. Accordingly, we authorize utilities to propose steps like implementing terms of use and registration requirements when they

[56] Boulder Initial Comments, p. 16 February 5, 2021.

[57] Public Service, Supplemental Initial Comments, p. 51, February 2, 2021.

bring forward proposals to implement a web portal. Access restriction is allowed, but not required, as we do not want to set the expectation that every metric will be available only by a log-in, given the objectives for the web portal that we laid out previously. To prevent duplication, we also move language from prior Rule 3540 related to terms of use and denial of access, which are more appropriate for this rule.

170. We decline to authorize regulated utilities to propose or implement NDAs at this time. We are concerned that NDAs may be impractical for businesses like DER developers who must work with clients to make the data that they view on the web portal useful. Public Service has not put forward a proposal that any kind of NDA would be suitably tailored to allow reasonable use, including for market activities that are contemplated by the DSP process.

171. We further decline to authorize regulated utilities to propose or implement background checks. Public Service has provided evidence that two utilities implement background checks. It has not explained what a background check would be designed to identify in an individual user's record such that it would represent a meaningful but narrowly tailored security precaution. We are concerned that such requirements may represent hurdles that limit access to information without a clear showing as to their appropriateness or real potential to mitigate risk.

c. Rule 3541(c). Information Presented on Web Portal

172. Proposed paragraph (c) clarifies what kinds of information the web portal should provide. The version of this rule in the NOPR included a prescriptive list of content, such as distribution system characteristics and DER forecasts. We recognize that many of these metrics could be useful to participants, and indeed, they suggested others beyond what were originally

set forth by the NOPR.[58] However, upon review of participants' comments, we are concerned that including overly prescriptive requirements for information in rules could result in a web portal that is either overbuilt or insufficient compared to what users need to accomplish the objectives of the DSP process, while becoming expensive to ratepayers. Furthermore, as the technologies and data on the system itself continue to develop, we find that an overly prescriptive list, in rule language, does not provide the type of dynamic, responsive treatment that these data issues will require. They will need to mature and respond to the situation and should be more flexible than prescriptive data points listed in a rule would allow for.

173. In Post-Hearing Comments, COSSA/SEIA discussed the importance of hosting capacity maps to use cases like streamlining interconnection of DERs. Based on experience in other states as conveyed by participants, and based on the opportunities that additional data would provide for users of the web portal, we require that the web portal include at minimum the HCA as described in Proposed Rule 3531(a)(II); information about DER programs that customers can participate in; and additional content as directed by the Commission. As we previously directed, the HCA map presented on the web portal should include at least the information required by the Minnesota Public Utilities Commission. The web portal is a tool, but it is not the only tool to deploy DERs or NWAs. While we encourage utilities to develop more robust web portals that evolve over time to meet the objectives of the DSP process, we expect that process to occur through the implementation steps laid out in paragraph (d).

d. Rule 3541(d). Implementation of the Web Portal

174. Proposed paragraph (d) establishes a process for implementing and enhancing utilities' web portals over time. Consistent with the discussion above, the intent of rearranging

[58] COSSA/SEIA Post-Hearing Comments, Exhibit III, p. 2, April 16, 2021.

and revising this rule was to create logical steps for engaging users and coordinating the implementation of the web portal with the DSP application process. This will promote flexibility and allow for appropriate features of the web portal to be established specific to each utility's technological capabilities, costs, and stakeholder needs. By allowing for web portal information, use cases, and functionalities to be developed utility-by-utility, we reject Black Hills' proposal in its Supplemental Closing Comments to eliminate the web portal requirement for smaller utilities, although we note our prior allowance that smaller utilities may initially present their HCA in spreadsheet format.

175. Subparagraph (d)(I) sets the expectation that the utility will engage potential users of its web portal from multiple sectors to develop a proposal for implementation. As is discussed above, the web portal should be designed to meet the overall objectives of the DSP process. Throughout this Proceeding, there have been calls for a workshop related to treatment of data in the DSP process.[59] We do not believe that such a workshop would be useful in the abstract. However, in Post-Hearing Comments, COSSA/SEIA raised significant concerns with the accuracy and usability of Public Service's existing online HCA tool. Therefore, we believe it appropriate to build specific stakeholder engagement requirements into the Web Portal rule. Because we declined to prescribe specific data protection practices for the DSP process under Proposed Rule 3540, it will be necessary for the utility to engage directly with potential users of the web portal, who have a role in making the DSP process successful, to understand what information they need and accordingly what practices are reasonable to apply from a protection standpoint.

[59] *See, e.g.,* Black Hills Closing Comments, p. 2, April 16, 2021; Public Service Initial Comments p. 24, January 29, 2021.

176. While we do not delineate specific sectors that should be engaged as part of the rule, our expectation is that this engagement should be substantive and should include representatives from diverse perspectives, including DER developers or service providers, DER program managers, future NWA bidders, state agencies, local governments, disproportionately impacted communities, and academia. Stakeholders should be selected with consideration to at least the four objectives for the web portal that we set forth previously.

177. Subparagraph (d)(II) describes the web portal proposal that utilities should file within their first DSP applications. As previously mentioned with paragraph (c), we have transitioned many prescriptive requirements for functionalities into requirements for proposals addressing certain functionalities. The specifics of the web portal should be developed with consideration toward the objectives of the DSP process and the needs of users without being overly protective in an area where the risks or costs would not warrant that. While Proposed Rule 3541 provides for commonalities across electric utilities—such as the requirement that the web portal include the HCA—it allows for utility-specific variations. We encourage utilities to coordinate as they implement web portals to create consistency in how information is formatted, labeled, and presented.

178. Subparagraph (d)(II)(B) would require the utility to describe the use cases it intends to implement through the web portal to meet the objectives of DSP, such as the four we proposed above. Again, the description of use cases should develop through engagement with stakeholders, and we include this language to emphasize how critical we believe stakeholder engagement to be. For example, engagement with stakeholders may reveal that some of the system and historical data required to be filed pursuant to Proposed Rule 3531(a)(I) should be included on the web portal, along with the HCA map, to achieve various use cases.

179. Furthermore, we could envision that engaging representatives from disproportionately impacted communities in response to the objective related to identifying how utilities are performing as against State energy policies may lead to a proposal that DER deployment be mapped geospatially to understand whether particular geographic areas are underserved. Stakeholders may wish to understand if areas are underserved due to the need for distribution grid upgrades to accommodate DERs, or if innovative pilots would be appropriate to ensure that DER and NWA participation is more equitably distributed. By engaging with users, utilities could understand at what level this data may be useful to provide and whether components of it should be publicly available from a policy perspective (such as heat maps of DER participation) versus access-restricted (such as distribution grid status information). We do not presume that this specific use case will be filed in future DSP applications, but by this rule, we encourage utilities and stakeholders to work toward the web portal being a manageable and useful tool.

180. Subparagraph (d)(II)(C) requires a utility to propose how it plans to treat data as publicly available or access-restricted, and whether there is data relevant to the web portal for which confidential or highly confidential treatment is being sought. As described in paragraph (c), we have reduced the initial data *requirements* associated with the web portal. However, by this paragraph, we clarify that the utility should be analyzing all of the data it puts forward in the DSP application more broadly as part of winnowing down to specifically what metrics, access restrictions, and data protections are proposed for the web portal in order to achieve the proposed use cases. We further expect that utilities will file as part of the proposal, the terms of use associated with the web portal and the processes associated with any account creation process, such as information required and turnaround times for account approval.

181. The record in this Proceeding is insufficient for us to make findings about the treatment of whether certain types of data are potentially sensitive or should be treated in particular ways. However, we recognize COSSA/SEIA's concern that claims for protective treatment must involve "meaningful substantiation."[60] Accordingly, utilities will be required to produce more specific analysis at the beginning of a DSP application proceeding. Both Public Service and COSSA/SEIA presented data considerations in matrix formats. In particular, the matrix format set forth by Public Service in Supplemental Attachment B to its Initial Comments could be a useful starting point for presentation of this kind of detailed information, albeit with more substantive feedback from potential users of the Web Portal. If parties to these future proceedings disagree with the proposed treatment by utilities, we expect them to be similarly precise in their arguments, so that we can understand why information is needed and the trade-offs associated with different treatments.

182. Subparagraph (d)(II)(F) provides some flexibility in the frequency of data updates that allows for consideration of stakeholder need and challenges utilities may have in assembling, cleaning, and refreshing data. However, due to the centrality of the HCA use case, we provide that the HCA should be updated at least quarterly on the web portal. We view quarterly HCA updates as a temporary compromise between monthly and bi-annual. We recognize the significant investment into new software and training that will be involved in a more accurate and granular HCA. As the software and data availability improve over time, we expect that more frequent updates to the HCA will be necessary.

183. Subparagraph (d)(II)(G) allows, rather than requires, the use of Application Programming Interface (API) capabilities. Developing APIs could allow for creative uses of data,

[60] COSSA/SEIA Reply Comments, p. 6-7, February 19, 2021

such as a State agency combining data from multiple regulated utilities' websites to present a fuller image of some issue, such as DER adoption, to the public. We see the value in moving in this direction and encourage utilities to look at APIs as an option for enhancing the usability of web portals. However, we decline to mandate a particular technological function prior to having utility-specific evaluations of capabilities, and knowing specific metrics for which users may have interest and need.

184. Finally, subparagraph (d)(II)(H) requires utilities to include proposals for how to collect ongoing user feedback. Joint Stakeholders proposed language that the web portal shall provide a means for users to submit feedback on the accuracy and content of the HCA.[61] We support the concept that regulated utilities must collect feedback on the accuracy and usability of the web portal and must discuss that feedback as part of their annual compliance reports, among other places. However, we decline to specify the means by which this feedback is collected, as regulated utilities have a variety of different venues by which they engage with potential users of the website. We would prefer substantive feedback and engagement as opposed to a prescriptive collection method. If this method does not provide a sufficient means for users and stakeholders to provide feedback and for that feedback to be taken seriously, these requirements could always be reevaluated at a later date.

e. Rule 3541(e)-(f). Future Updates

185. Finally, paragraphs (e)-(f) set expectations for updating the web portal in subsequent DSP applications after the first. As a tool developed to meet a set of needs, we expect the web portal to be dynamic. The DSP application process can provide an opportunity to reevaluate its use cases, data treatment, and functionalities. However, we also expect that

[61] Joint Stakeholders' Consensus Rules Att. A p. 17, April 16, 2021.

improvements to functionality may occur outside adjudicated applications and thus also establish an annual reporting mechanism that provides the Commission and stakeholders with insight to this ongoing process.

19. Rule 3542. Evaluation and Reporting

186. Proposed Rule 3542 directs the utilities, beginning with their second DSP applications, to file a report that describes the progress on implementation of NWAs, a review of the NWA CBA methodology used, as well as proposed performance metrics and benchmarks to track successful implementation of the Plan. The report should also describe any lessons learned from the DSP process and identify ways to improve methodologies through research before the next filing.

187. Public Service suggests that the existing distribution system and grid security assessments required under Commission Proposed Rule 3538 should be referenced to the Evaluation and Reporting section of rules. These reports could be filed contemporaneously with each Phase I Application, consistent with reporting requirements already required under the Commission's Proposed Rule 3542.

188. We agree with Public Service's clarifying additions to Rule 3542.

B. Conclusion.

189. Attachment A of this Recommended Decision contains the rule amendments adopted by this Decision with modifications to the DSP Rules proposed in the NOPR indicated in redline and strikeout format (including modifications in accordance with this Recommended Decision).

190. Attachment B of this Recommended Decision contains the rule amendments adopted by this Decision in clean and final format.

191. The Hearing Commissioner finds and concludes that the Distribution System Planning proposed in the NOPR, as modified by this Recommended Decision, are just and reasonable and should be adopted.

192. Pursuant to the provisions of § 40-6-109, C.R.S., it is recommended that the Commission adopt the attached DSP Rules.

III. ORDER

A. The Commission Orders That:

1. The Distribution System Planning Rules contained in 4 *Code of Colorado Regulations* 723-3, set forth in legislative (redline and strikeout) format in Attachment A and in clean format in Attachment B, are adopted. Both attachments are also available in the Commission's E-Filings system at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=20R-0516E

2. This Recommended Decision shall be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

3. If this Recommended Decision becomes a Commission Decision, the relevant rules are adopted on the date the Recommended Decision becomes a final Commission Decision.

4. As provided by § 40-6-109, C.R.S., copies of this Recommended Decision shall be served upon the participants and the representative group of participants, who may file exceptions to it.

a. If no exceptions are filed within 20 days after service of this Recommended Decision or within any extended period of time authorized, or unless the decision is stayed by the Commission upon its own motion, the Recommended Decision shall become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S.

b. If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the participants may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set out by the hearing commissioner and the participants cannot challenge these facts. This will limit what the Commission can review if exceptions are filed. If exceptions to this decision are filed, they shall not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

(S E A L)

STATE OF COLORADO
THE PUBLIC UTILITIES COMMISSION
NIL SINE NUMINE

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

MEGAN M. GILMAN

Hearing Commissioner

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

*   *   *   *

[indicates omission of unaffected rules]

DISTRIBUTION SYSTEM PLANNING

3525. Applicability

This rule shall apply to all electric utilities in the state of Colorado that own distribution facilities except municipally owned electric utilities and cooperative electric associations that have voted to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-104, C.R.S.

3526. Overview and Purpose.

The purpose of these rules, as directed by § 40-2-132, C.R.S., is to require electric utilities to file a Distribution System Plan (DSP) that enables the Commission to review and evaluate the utility's investments in the distribution grid to ensure that they cost-effectively support grid adequacy, reliability and resilience, while simultaneously supporting diversification of energy supply through distributed energy resources, expanding the utilization of non-wire alternatives that may reduce the need for conventional distribution grid investment, and preparing for new expectations upon on the distribution system. These rules should also establish a proactive and transparent process for enhancing understanding of key distribution system characteristics.

3527. Definitions.

The following definitions apply to rules 3525 through 3542. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Ancillary services" means the functions that maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event. Ancillary services include but are not limited to synchronized regulation, contingency reserves, flexibility reserves, voltage and frequency response, power factor corrections, and spinning reserves.

(b) “Capacity need” means a distribution grid capacity constraint or shortfall projected within a ten-year period.

(c) “Demand flexibility” means the ability, often using communication and control technology, to shift electricity use across hours of the day while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality and delivering net benefits to the system, customers, or society.

(d) “Demand response measures” or “demand response” or “DR” means any modulation in customer electric usage at targeted times, including reduction of usage or shifting of usage from one time to another, or interruption or curtailment of electric usage, either with load control equipment or in response to incentives, a signal, or changes in the price of electricity designed to induce changes in electricity use at specific times.

(e) “Direct current fast charger” means a high-power fast charging method of at least 50 kW capacity used to resupply an electric vehicle using direct current electricity, typically 208/480V three-phase.

(f) “Distributed energy resources” or “DER” may include, but are not limited to, distributed generation, energy storage systems, electric vehicles, microgrids, fuel cells, and demand side management measures including energy efficiency, demand response, and demand flexibility that are deployed at the distribution grid level, on either the customer or utility side of the meter. DER can be used to optimize energy use and generation to satisfy the energy, capacity, or ancillary service needs of the distribution grid.

(g) “Distribution system plan” or “DSP” means the compliance plan filed in accordance with rule 3528.

(h) “Energy efficiency measures” are measures that target consumer behavior, equipment, or devices that result in the decrease in electricity usage of customers without detriment to end-use services.

(i) “Grid availability” means the hours per year when the utility makes the grid or a portion of the grid available for use not only by load but also by distributed generation and demand response.

(j) “Grid need” means the need for energy, capacity, ancillary services, reliability, or resiliency services to address a forecasted deficiency on the electric distribution system.

(k) “Hosting capacity” means the amount of distributed generation, including distributed generation paired with battery storage, 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.

(l) “Locational value” means an analysis of distributed energy resources that incorporates location-specific incremental net benefits to the electric grid.

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

(n) "Microgrid" means a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that can act as a single controllable entity with respect to the grid. A microgrid is capable of connecting and disconnecting from the centralized grid to enable the microgrid to operate in both grid-connected or island-mode.

(o) "N-1 event" means an outage event of one distribution or transmission element such as a transformer, feeder, or transmission line that may cause load to shift to other elements as backup. An N-1 event indicates a need for additional reliability capacity if it is determined to cause a potential overload on elements carrying energy to accommodate the event.

(p) "Non-Wires Alternative" or "NWA" means the strategic deployment of distributed energy resources by a utility or a third party and associated control or aggregation of systems and technologies intended to cost-effectively defer or avoid the need for Major Distribution Grid Projects. An NWA is intended to reliably reduce load, congestion or other constraints at times of peak demand in targeted locations on the grid. NWAs can include one or multiple DER, including but not limited to demand response measures, energy efficiency, energy storage, and distributed generation. NWA projects can include these and other investments individually or in combination to meet the specified need.

(q) "Pilot" means a utility offering to test a new use or deployment of DER for a set period of time with a specified end date and number of customers, wherein the utility seeks to gain experience or expertise, and to inform the Commission.

(r) "Program" means an ongoing, long-term offering by the utility with no specified end date that utilizes or deploys DER on the distribution grid in a manner that provides system benefits or cost savings.

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

(t) "Reliability need" means a risk of failure requiring mitigation due to inadequate capacity or voltage support, or an N-1 event on the distribution grid.

(u) "Resilience" is the ability of the distribution grid to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.

3528. Distribution System Plan Filing Requirements.

A utility with over 500,000 customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2022. A utility with 500,000 or fewer customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2023.

(a) Each DSP application filing shall conform to the application requirements contained in rules 3002 and rule 1303 of the Commission's Rules of Practice and Procedure.

(b) Within 30 days of the filing of the application, the Commission shall issue a decision addressing whether the contents of the DSP meet Commission standards based on the information provided by the utility set forth in paragraph 3528(d).

(c) If the DSP identifies major distribution grid projects that meet the NWA suitability screening criteria put forth in paragraph 3534(a), then the DSP proceeding shall consist of two phases.

(I) Within the same proceeding and subject to paragraph 3528(b), the utility shall file a Phase II DSP within 120 days of the filing of the Commission's order establishing the final Phase I DSP. The Phase II DSP shall adhere to the requirements of paragraph 3529(b).

(A) Within 30 days after the filing of the Phase II DSP, parties may submit comments pertaining to the Phase II DSP.

(B) Within 15 days after the deadline for initial comments on the Phase II DSP, parties may submit reply comments.

(d) If the utility claims that any of the requirements set forth in rules 3529 through 3541 are not yet practicable to provide or are currently cost-prohibitive to provide, the utility shall indicate for each requirement:

(I) why the information is not yet practicable or is currently cost-prohibitive, what information could be provided in the alternative and how that alternative information would achieve planning and policy objectives.

(II) how the information could be obtained in future filings, and if so, at what estimated cost, and on what timeframe;

(III) what the benefits or limitations of filing the data in future reports would be as related to achieving the planning and policy objectives; and

(IV) if the information cannot be provided in future reports, what information could be provided in the alternative and how it would achieve planning and policy objectives.

(e) The utility shall file a final DSP action plan in accordance with rule 3536, including all required modifications, within 60 days of the Commission's final decision.

(f) The utility may file, at any time, an application to amend the contents of a DSP approved pursuant to paragraph 3536(c). Such an application shall meet the requirements of paragraphs 3002(b) and 3002(c), shall identify each proposed amendment, shall state the reason for each proposed amendment, and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

(g) Utilities are encouraged to convene regular, informal stakeholder meetings to discuss DSP-related issues and to inform the contents of DSP applications. The utility shall convene at least one stakeholder meeting at least 90 days prior to the filing of the DSP. As part of these

stakeholder meetings, the utility shall solicit input on future programs and/or pilots and solicit feedback on both the hosting capacity analysis and the web portal. The utility shall make all reasonable efforts to engage local governments and community organizations representing disproportionately impacted communities. The Commission may, at its discretion, require utilities to host stakeholder discussions regarding specific DSP topics.

3529. Contents of the Distribution System Plan.

(a) The utility shall file a Phase I DSP with the Commission that contains the information specified below. When required by the Commission, the utility shall provide any relevant studies, additional data, and work-papers to support the information contained in the plan. The DSP shall include the following:

(I) 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;

(II) a description of how the distribution grid may evolve over the next five and ten years due to various factors, such as increasing DER penetration, the expansion of beneficial electrification programs and other electrification, advanced metering infrastructure, increasing demand flexibility, energy efficiency and other emerging technologies. The utility should discuss the challenges and opportunities presented by the emergence of new technology as well as plans they have to adapt to or utilize these changes to the grid;

(III) 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;

(IV) distribution system forecasts, as described in rule 3530;

(V) an assessment of the existing distribution system, as described in rule 3531;

(VI) an assessment of grid needs, as described in rule 3532;

(VII) a description of grid innovations and any proposed pilots and programs, as described in rule 3533;

(VIII) NWA suitability screening results, as described in paragraph 3534;

(IX) a proposed NWA cost benefit analysis methodology, as described in paragraph 3535;

(X) a Phase I action plan, as described in subparagraph 3536;

(XI) a proposal for cost recovery, which may include an incentive, as described in rule 3538;

(XII) a security assessment, as described in rule 3539.

(XIII) a proposal for implementation of a web portal as described in paragraph 3541(d);

(XIV) a description of the stakeholder engagement process, as described in paragraph 3528(g); and

(XV) 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.

3530. Distribution System Forecasts.

(a) Forecast requirements. The utility shall prepare energy and demand forecasts for each year within the ten-year planning period. The utility shall also prepare ten-year forecasts for load growth on the distribution grid, including the growth of various types of DERs connected to the distribution grid. Forecasts should be based on at least two growth scenarios (State Policy and High), including 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. Forecasted growth should include the following:

(I) peak load growth at each substation, by year;

(II) peak load growth at each substation transformer by year;

(III) peak load growth on each feeder, by year;

(IV) coincident peak and non-coincident peak load growth at substations, transformers, and feeders, by voltage class;

(V) load growth associated with beneficial electrification, by substation transformer and by feeder under each scenario in subparagraph 3530(a)(X);

(VI) load growth due to new planned neighborhoods or housing developments,

(VII) net load impacts due to DER adoption under each scenario in subparagraph 3530(a)(X);

(VIII) net load impacts due to demand side management, demand response, and demand flexibility;

(IX) approved CSG capacity in RES Plans and anticipated CSG capacity additions beyond the current effective RES plans;

(X) forecasts of DERs and NWA should include ten-year scenarios that project expected growth of DERs and NWA, including expected geographic dispersion at the distribution feeder level and impacts on distribution planning. Scenarios shall be designed to meet or exceed current state policy such as those related to greenhouse gas (GHG) reductions, increased use of DERs, electrification, distribution reliability, resiliency, and transmission system needs. Scenarios shall include key inputs including growth of peak exported generation from distributed solar generation; growth of peak exported generation from distributed battery storage systems; and growth of peak exported generation from all other distributed generation. Scenarios shall be based on the following criteria:

(A) State Policy Goal Scenario: Adopts a current forecast case for DER and NWA deployment for distribution planning at the feeder lever, down to each line section, assuming compliance with current state policy goals.

(B) High Growth Scenario: Adopts a high growth case for DERs. This scenario should exceed state policy goals, which may include long-term GHG reductions, and beneficial electrification at levels higher or faster than required in state statute or in-current state policy goals. Additionally, the High Growth Scenario may improve upon performance in areas of demand flexibility, distribution reliability, resiliency, and transmission system needs beyond a business as usual projection.

(b) The utility shall provide all assumptions and methodologies that are inputs into the forecasting scenarios in paragraph 3530(a).

3531. Assessment of Existing Distribution System.

(a) System overview and substation historical data.

(I) To identify and assess needs on the distribution system, each utility shall provide a map of existing and planned substations within its service territory, as well as tabular information about the current design capacity, and performance of each substation and substation transformer. The assessment should also include the status of advanced infrastructure deployment which may be made by reference to other reports or filings. At a minimum, this should include the following information for each substation and substation transformer on the utility's distribution grid:

(A) maximum rated capacity of each substation transformer;

(B) peak hourly demand on each substation transformer for the past three years;

(C) capacity margin for each substation transformer;

(D) advanced functionality capabilities of each substation transformer;

(E) number of feeders served by each substation and substation transformer;

(F) maximum rated capacity of each feeder;

(G) peak hourly demand on each feeder for the past three years;

(H) capacity margin for each feeder;

(I) percentage of grid availability;

(J) minimum daytime load;

(K) aggregate miles of underground and overhead wires, categorized by voltage class;

(L) monitoring capabilities and data collection on the distribution system, such as the substations and feeders for which the utility has real-time supervisory control and data acquisition (SCADA) capability;

(M) amount of distributed generation installed on the system (number of systems and nameplate capacity in kilowatts (kW) by generator types, organized by substation or feeder);

(N) description of NWA on the system, organized by substation or feeder; including annual cost savings and greenhouse gas emissions reductions;

(O) amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours (kW and kWh));

(P) estimated number of EVs and Level 2 and DCFC EV charging stations organized by substation or feeder;

(Q) estimated demand flexibility capacity on the system and historic utilization of those flexibility capabilities;

(R) voltage and power quality data for the past three years; and

(S) location of highly seasonal circuits as defined by subparagraph 3667(a)(IV).

(II) Hosting capacity analysis.

(A) As part of its DSP, each utility shall develop a hosting capacity analysis of the distribution system.

(B) The analysis shall determine the hosting capacity on a particular feeder, feeder section or substation at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

(C) The hosting capacity analysis shall be performed using a load flow analysis and forecasted distribution facilities and their capacity, configuration, loading, and voltage data gathered at the substation, feeder, and primary node levels where available.

(D) The utility shall perform scenario analysis to evaluate hosting capacity need under normal and planned and unplanned contingency conditions, as well as under the High Growth scenario.

(E) The utility shall provide a detailed description of the methods and outcomes it used to perform the hosting capacity analysis.

(F) The hosting capacity analysis shall reflect that which appears in the web portal as described in rule 3541. The utility shall also provide a detailed narrative describing the utility's progress towards advancements to the accuracy and value of the hosting capacity analysis and providing real-time hosting capacity data. This should include a description of how its hosting capacity analysis currently advances customer-sited DER (in particular distributed renewable electric generation and energy storage systems), how the utility anticipates the hosting capacity analysis will aid in identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which the utility anticipates customer benefit stemming from the hosting capacity analysis.

(G) For their first DSP filing, utilities with 500,000 or fewer customers shall provide an Excel spreadsheet (or equivalent format) by feeder of either daily daytime minimum load or, if daytime minimum load is not available, daily peak load with the time granularity specified.

3532. Grid Needs Assessment.

(a) The utility shall provide a summary analysis of the energy, capacity, ancillary services, and reliability needs and constraints on a utility's distribution system and solutions to those needs.

(b) The grid needs assessment shall include an analysis regarding the suitability of non-wires alternatives to mitigate identified needs and recommendations for the deployment of utility infrastructure upgrade solutions versus the procurement of non-wires alternative solutions to address any identified needs.

(c) The grid needs assessment shall address existing and forecasted needs over a ten-year planning period that could result in a major distribution grid project.

(d) The grid needs assessment shall include each of the following parts.

(I) An assessment of critical needs.

(A) The utility shall provide an assessment of critical capacity and reliability needs that must be addressed within the ten-year planning horizon.

(B) The assessment shall include a review of all planned, proposed and potential major distribution grid projects which will be required to address constraints related to substation transformers and feeders that are forecasted to have insufficient capacity to adequately serve peak load or reliability needs over the next ten years.

(C) The assessment shall be divided into two parts – one detailing short-term needs within zero to three years, and one detailing longer-term needs in four to ten years.

(D) The data used for the assessment shall be provided in megawatt values in tables, in a logical spreadsheet form (both printed and functional Excel spreadsheet formats) and graphically as a map in executable ARC GIS or similar format.

(E) The assessment of critical needs will be provided via the web portal, described in rule 3541. Any notable updates to the web portal should also be made in this section of the DSP.

(F) The assessment shall include a review of the capability of the distribution system and any needs incurred to interconnect approved CSG capacity in the utility's current SGIP queue, the capacity approved in its most recent RES Plan but not yet acquired, and a reasonable expectation of future CSG capacity during the DSP planning period.

(II) Exemptions for short-term planning needs.

(A) For any grid needs identified during the current planning cycle, which require service within thirty-six months, the utility shall be exempt from the rules governing solicitations for Major Distribution and Transmission Grid projects - ule 3537. As part of its assessment, the utility shall explain why this grid need was not previously identified.

(III) The utility's current distribution plan for distribution grid investments, as well as the total capital budget including the past three years and the next five years of projected budget. Budgets shall be broken down by relevant budget categories.

(IV) Fast charging locations for electric vehicles. The utility shall use the results of the grid needs assessment to identify locations where substation transformers and feeders have sufficient capacity for hosting multiple direct current fast chargers for electric vehicles. Utilities will also assess vehicle-to-grid (V2G) opportunities as potential NWA projects.

(V) An identification of any long-term needs identified in the grid needs assessment for which ratable procurement may avoid or defer the anticipated need driven by steady load growth, including geographically targeted deployment of demand flexibility, demand response, and energy efficiency measures.

3533. Grid Innovation.

(a) The DSP shall address DSP pilots and programs that are either in progress, planned, or have been suggested by other parties and found to have merit by the utility. The DSP shall identify any barriers to deployment of DERs and NWA. Such barriers may include but not be limited to integration or interconnection of DERs and NWAs, barriers that limit the ability of a DER and NWA to provide benefits, and barriers related to distribution system operation and infrastructure capability. This section shall include, but not be limited to:

(I) Within each DSP, the utility may propose new pilots and programs designed to gain experience integrating DER, NWA or other new distribution technologies in a way that improves system performance, minimizes system costs, increases system resiliency and/or reliability, and/or reduces greenhouse gas emissions including from reduced curtailment of renewable energy. Such pilots and programs may be proposed as solutions to help solve identified grid needs identified under rule 3532.

(II) New proposed pilots. Within each DSP, the utility may propose new pilots. Pilots shall not be required to pass a cost-benefit test; however, the Commission shall determine that the pilot can be implemented at a reasonable cost and rate impact. Each of the proposed pilots shall, at a minimum, include:

(A) a description of what the utility seeks to learn through the pilot with specific goals and metrics;

(B) an explanation of how the pilot can be scaled to enable the utility to achieve objectives described in the plan pursuant to rule 3529;

(C) the specific DER and NWA technology or technologies eligible for the pilot, including any operational requirements;

(D) a description of any geographic or locational focus of the pilot;

(E) the customer classes that may participate in the pilot;

(F) a description of the potential benefits the utility expects the pilot technology to demonstrate;

(G) a description of the costs of the pilot, including a cap on costs for each pilot;

(H) criteria for evaluation of the pilot and an evaluation plan that includes a calculation of pilot costs, schedule, and a summary of pilot benefits, including quantified benefits, as available;

(I) a description of the use of any targeted incentive payments, or other incentives, provided to participants;

(J) a description of the mechanism to acquire equipment, technologies, vendors, and participants in the pilot; and

(K) a description of how the pilot will provide health, safety, environmental, or financial benefits to disproportionately impacted communities.

(III) New proposed programs. Within its DSP, the utility may seek approval for a new program to better integrate DER and NWA or other distribution technologies into its business practices in a way that improves system performance, minimizes costs, increases system resiliency and reliability, or reduces emissions. Proposed programs may be successors of completed pilots; however, a utility does not need to have conducted a pilot in order to seek approval for a new program.

(IV) The utility may propose pilots or programs developed internally and shall also accept third-party proposals for pilots and programs at any time. For a third-party pilot or program to be considered in a DSP, it must be received by the utility at least six months prior to the DSP filing deadline. 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. For any proposal not considered, the utility shall explain why it was not considered.

(V) Updates on existing pilots and programs. Within its DSP, the utility shall provide a narrative status update on all active pilots and programs approved in prior DSPs. The utility may also seek reauthorization of existing programs within a DSP. As part of its first DSP, the utility is encouraged to evaluate whether any existing reporting obligations outside the DSP related to distribution system pilots, programs, or projects should be centralized within the DSP process. Upon Commission approval, and notice filed within the original proceeding, such reporting obligations shall be transferred to DSP proceedings.

(b) NWAs and pilots may include the use of targeted incentive payments to encourage DER adoption or optimize the use of existing DERs by customers in specific locations, to provide locational value to the system. Such incentives shall be accounted for in the cost benefit analysis as described in rule 3535 and shall be recovered in a manner similar to other distribution-grid related expenditures.

3534. NWA Suitability Screening.

(a) Major distribution grid projects identified to be necessary in the grid needs assessment conducted pursuant to rule 3532 shall be subject to an NWA suitability screening to determine if a NWA may be a suitable alternative to traditional utility infrastructure solutions.

(b) The NWA suitability screening is performed by the utility and includes the following criteria:

(I) the project is anticipated to occur during the ten-year planning horizon;

(II) the constraint is due to thermal loading, voltage, capacity or reliability issues and could be resolved by a DER, a reduction in peak demand loading, a reduction in energy consumption, or load shifting on the transmission or distribution facilities; and

(III) the conventional solution is still within the planning or design stage, with no major equipment on order, received, or installed that cannot be repurposed for other uses.

(IV) A utility may request that projects such as wildfire mitigation, relocations, and asset health and renewal projects may be excluded from suitability screening. Such requests should be substantiated to show why the NWA suitability screening is not possible or could not reasonably result in an alternative to traditional utility infrastructure.

(c) The utility may seek a waiver from these requirements on a case-by-case basis if necessary, to preserve reliability, serve economic development needs, or to meet other unforeseen circumstances where a non-wires alternative cannot provide the planning constraint.

(d) For all major distribution grid projects identified as meeting all of the NWA suitability screening, the utility shall conduct a technology-neutral competitive solicitation for NWAs to defer, reduce, or avoid the costs of the major distribution grid projects.

3535. NWA Cost Benefit Analysis.

(a) In order to assess the cost-effectiveness of a potential NWA solution that meets the NWA Suitability Screening in rule 3534, the utility shall:

(I) develop and publish a cost benefit methodology that will be provided in the utility's DSP;

(II) assess the proposed NWA solution using a cost-benefit methodology that considers the approach as put forward in the National Standard Practice Manual and specifically including the following costs and benefits: avoided or deferred costs associated with an NWA solution, sub-transmission, substation transformer additions or upgrades, feeder capital and operating costs, distribution power quality equipment, reliability and resiliency costs, energy and capacity value of generation, capacity value of storage, greenhouse gas emissions including the Commission approved social cost of carbon useful life of NWA and traditional solutions, and dispatchability and availability of the technology. If the utility is proposing a performance incentive as part of cost recovery for the NWA pursuant to paragraph 3538(d), it shall include the cost-benefit analysis both with and without the performance incentive included as a cost of the project;

(III) provide a description of DSP goals, compliance with statute, rules, and requirements, and additional relevant principles; and

(IV) assess the proposed distribution system costs, direct system benefits, indirect system benefits, and system sensitivity analysis.

(b) The utility may also propose an alternative or adjusted cost-benefit methodology if it does not believe that the full costs and benefits of the NWA solution are being counted.

3536. Action Plan.

(a) The utility shall provide a five-year action plan for distribution system investments and activities within its Phase I DSP which will serve as an application report for the Commission and stakeholders to rely upon when evaluating distribution system planning projects, pilots, and programs.

(b) The Phase I action plan shall include the sequence of events and timelines for each action that will not require a solicitation process following Phase I, including:

(I) the implementation of NWAs identified through the NWA cost benefit analysis process;

(II) the implementation of proposed pilots and programs as specified in rule 3533;

(III) the implementation of major distribution grid projects that were determined to be the best option to address grid needs;

(IV) system interoperability and communications strategy;

(V) costs and plans associated with obtaining data necessary for the evaluation of NWAs, pilots and programs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles);

(VI) interaction of planned or proposed investments with other utility programs and the effects on existing utility programs and tariffs; and

(VII) the implementation of major distribution projects intended to cost-effectively interconnect the approved and reasonably forecasted CSG capacity, including that approved by RES Plans in effect during the planning period;

(c) Subject to paragraph 3528(b), the utility shall provide an updated action plan with its Phase II DSP. This plan shall include the sequence of events and timelines for NWAs identified in the solicitation process, including:

(I) the implementation of NWAs identified through the NWA analysis process;

(II) an updated system interoperability and communications strategy;

(III) costs and plans associated with obtaining data necessary for the evaluation of NWAs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles); and

(IV) interaction of planned or proposed NWA investments with other utility programs and the effects on existing utility programs and tariffs.

3537. NWA Solicitation Process (Phase II).

(a) The utility shall propose in its DSP (Phase I) Application appropriate timelines for the release of the RFP(s), the receipt of bids, evaluation of bids, the utility's proposal to the Commission, the filing of the independent evaluator report, party comments in response to the independent evaluator report, and the Commission decision. These timelines should consider similar timelines as expressed in the Electric Resource Planning Rules, specifically rule 3613. The timelines proposed by the utility and approved by the Commission in the DSP (Phase I) shall describe an appropriately expedited, comment-based NWA Solicitation Process (Phase II) to facilitate timely decisions and implementation of NWA bids.

(b) For projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria, an Independent Evaluator (IE) shall be retained.

(I) The utility shall file for Commission approval the name of the independent evaluator. The Commission shall approve an independent evaluator by written decision during Phase I.

(II) The utility shall pay for the services provided by the independent evaluator pursuant to a contract approved by the Commission. The terms of such contract shall prohibit the independent evaluator from assisting any entity making proposals to the utility for subsequent resource acquisitions for three years.

(III) The utility shall work cooperatively with the independent evaluator and shall provide the independent evaluator immediate and continuing access to all documents and data reviewed, used, or produced by the utility in the preparation of its projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria and in its bid solicitation, evaluation, and selection processes. The utility shall make available the appropriate utility staff to meet with the independent evaluator to answer questions and, if necessary, discuss the prosecution of work. The utility shall provide to the independent evaluator, in a timely manner so as to facilitate the deadlines outlined in these rules, bid evaluation results and modeling runs so that the independent evaluator can verify these results and can investigate options that the utility did not consider. If the independent evaluator notes a problem or a deficiency in the bid evaluation process, the independent evaluator should notify the utility.

(IV) All parties in the DSP proceeding other than the utility are restricted from initiating contacts with the independent evaluator. The independent evaluator may initiate contact with the utility and other parties. For all contacts with parties in the DSP proceeding, including those with the utility, the independent evaluator shall maintain a log that briefly identifies the entities communicating with the independent evaluator, the date and duration of the communication, the means of communication, the topics discussed, and the materials exchanged, if any.

(V) The independent evaluator shall generally serve as an advisor to the Commission and shall generally not be a party to the proceedings. As such, the independent evaluator shall not be subject to discovery and cross-examination at hearing.

(VI) Within 30 days of a utility selecting an NWA bidder to advance to Phase II, the independent evaluator shall file a report. The independent evaluator shall address in its report whether the utility's competitive acquisition procedures and bidding policy, including the assumptions, criteria and models, were sufficient to solicit and evaluate bids in a fair and reasonable manner, with any deficiencies specifically noted. The independent evaluator shall provide confidential versions of these reports to Commission staff and the OCC.

(c) All solicitations, unless requested by the Commission, or requested by the utility and approved by the Commission, shall be conducted in a technology neutral manner.

(d) The utility may require prospective bidders to sign non-disclosure agreements in order to obtain information deemed confidential or highly confidential.

(e) After final NWA bids have been selected by the utility, the utility shall update the elements of the Action Plan that pertain to NWAs.

3538. Approvals and Cost Recovery.

(a) The utility may seek Commission approval of a NWA, pilot, or program in its DSP application filing. Should such an approval be sought, the Commission may require a hearing specifically on the NWA pilot, or program in addition to the process described in rule 3536. The Commission may require the utility to demonstrate satisfactory compliance with appropriate benchmarks or performance metrics outlined in the Commission's decision approving pilots, programs or NWA or other components of the DSP. Utilities may seek approval to implement an NWA, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation. New pilots or programs should meet the standards and requirements set forth in paragraph 3533(a).

(b) A utility may seek any necessary approvals for a NWA, pilot or program pursuant to an approved DSP in other proceedings, including, but not limited to:

(I) demand side management planning;

(II) renewable energy standard compliance planning;

(III) transportation electrification planning; or

(IV) innovative technology pilot programs or demonstrations;

(c) 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. 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 reasonable. The utility may seek approval to implement NWAs, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation.

(d) In the application for approval of a DSP, the utility shall address how it anticipates recovering costs associated with the investments put forward in its DSP in accordance with subparagraph 3529(a)(XI).

(I) Investments made to implement an approved DSP shall be deemed to made in the ordinary course of business and shall be recovered through the normal implementation of the utilities rate mechanisms.

(II) The utility shall demonstrate that the investments made to implement an approved DSP do not undermine equitable access to other utility programs and do not materially impact the related utility program's targeted performance.

(III) The utility may propose a performance incentive for implementing any NWA, pilot, or program as a component of its cost recovery proposal. The performance mechanism, if proposed, shall also be included as part of the cost-benefit analysis specified in rule 3535. A performance incentive may include allocating to the utility a share of the cost-savings derived from NWA implementation as compared to the avoided capital investment.

(IV) For costs the Commission deems to be incurred outside the ordinary course of business, the utility may seek approval of a regulatory asset for recovery as part of the utility's next rate case, or may be placed in another cost recovery mechanism as proposed by the utility. The Commission shall establish the authorized rate of return on any regulatory asset created pursuant to this paragraph.

(e) 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.

(f) The utility shall file a final DSP, which may include required modifications, within 60 days of the Commission's final decision.

3539. Security Assessment.

(a) The utility shall provide a narrative assessment of the reliability and resilience of the distribution grid with respect to cybersecurity and physical security, including:

(I) current status of distribution grid reliability and plans for improving reliability, including areas of the grid where reliability problems have been identified, with plans for resolving them. Distribution grid reliability metrics (SAIDI and SAIFI at a minimum) should be provided for each year for the past three years for each substation;

(II) list of major outages, including cause and duration, involving 10,000 customers or more for each year for the past three years;

(III) analysis of cyber security issues or other threats to the distribution system and what efforts the utility is taking to ensure the distribution system is secure;

(IV) analysis of risks by substation posed by natural disasters such as wildfires, floods, severe storms, and a detailed description of efforts the utility is taking to increase system resiliency in the response to these risks;

(V) other plans aimed at improving distribution system resiliency; and

(VI) any pilots or programs, existing or proposed, aimed at increasing reliability and resiliency, using microgrids or other technology, should be discussed within the Grid Innovation section of the Phase I DSP, as described in rule 3533.

(VII) The utility may incorporate by reference any other filings or applications made to the Commission that are relevant to a discussion of distribution system reliability and resilience.

3540. Data Access, Privacy and Confidentiality.

(a) The utility shall disclose data necessary to implement these rules with appropriate levels of protection, considering sensitivity and public benefit. The utility shall identify and address the treatment of sensitive information in consideration of the objectives of DSP and as required by these rules.

(b) The utility shall not disclose personal information, as defined in paragraph 1004(x), or customer data, as defined in paragraph 3001(i). paragraph 3033(b) shall not apply to data releases under this rule.

(c) In each DSP application filing made pursuant to rule 3529, the utility shall file a list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information that the utility claims is highly confidential, and its proposed treatment of the information. For good cause shown the utility may seek to protect information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

3541. Web Portal.

(a) The utility shall make available a web portal that provide map-based and tabular data that is publicly available or access-restricted as further defined under this rule. Such web portal shall be designed to meet the objectives of the DSP and shall allow users to download data in tabular and geospatial formats

(b) The utility may not deny access to its web portal. To ensure the appropriate level of protection of sensitive information, the utility may require visitors to the web portal to take actions, including

(I) requiring visitors to acknowledge terms of service associated with its use, provided those terms do not preclude academic or public policy purposes; and

(II) establishing registration processes, including the creation of a username and password, and/or the use of multifactor authentication for access to sensitive information.

(c) A web portal shall include at least the following information:

(I) consistent with subparagraph 3531(a)(II), the utility's hosting capacity analysis;

(II) publicly available summaries, data, or links to existing information on the utility's website related to programs approved by the Commission that address the deployment of DERs, including, without limitation, pilots, tariffs, and incentives; and

(III) any additional content as directed by the Commission.

(d) Implementation of the web portal.

(I) Prior to filing its first DSP application pursuant to rule 3529, the utility shall engage potential users of the web portal from multiple sectors to develop a proposal for implementation of the web portal to be filed with the application.

(II) In its first DSP application pursuant to rule 3529, the utility shall present a proposal and timeline for developing a web portal that meets the requirements of this rule and includes:

(A) a summary of its process for identifying and engaging potential users of the web portal and the results of that process;

(B) a description of use cases that will be implemented through the web portal to meet the objectives of DSP;

(C) an evaluation of the data required in a DSP application pursuant to rule 3529 that addresses what data will be provided on the web portal and at what level of granularity, an evaluation of the risks and benefits associated with providing such data, proposals for treatment of sensitive information, and identifying any data for which confidential or highly confidential treatment is sought under the process provided in paragraph 3540(c);

(D) a proposal for providing functionalities that enhance the user experience, such as color-coding of substations, circuits, and feeders or ability to change the year of the data being displayed;

(E) a proposal for what information is currently available and can be provided on a web portal and what information requires approval by the Commission for incorporation onto a web portal;

(F) a proposal for updating data provided through the web portal, specifically addressing the quarterly updating of the utility's hosting capacity analysis as described in subparagraph 3531(a)(II);

(G) a proposal for enabling Application Programming Interface (API) capabilities where reasonable and appropriate; and

(H) a proposal for collecting user feedback on an ongoing basis.

(III) In subsequent DSP application proceedings, the utility shall provide an update on the status of implementing the web portal and any proposed changes to functionality and treatment of data. Prior to each application pursuant to rule 3529, the utility is encouraged to engage with stakeholders including users of the web portal, to identify changes.

(IV) The utility shall file an annual compliance report in the most recent DSP application proceeding that provides an update on the status of implementing the web portal, summarizes user feedback, and describes how the utility addressed that feedback, including any updates or revisions to the functionality of the web portal that are anticipated to occur prior to its next DSP application filing.

3542. Evaluation and Reporting.

(a) An assessment of the existing distribution system, as described in rule 3531.

(b) An assessment of Distribution Grid Security as described in rule 3539.

(c) Starting with its second DSP application, the utility shall describe the 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.

(d) The utility shall report lessons learned from the DSP process and identify ways to improve methodologies through research before the next filing.

3543. – 3549. [Reserved].

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

*   *   *   *

[indicates omission of unaffected rules]

DISTRIBUTION SYSTEM PLANNING

3525. Applicability

This rule shall apply to all electric utilities in the state of Colorado that own distribution facilities except municipally owned electric utilities and cooperative electric associations that have voted to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-104, C.R.S.

3526. Overview and Purpose.

The purpose of these rules, as directed by § 40-2-132, C.R.S., is to require electric utilities to file a Distribution System Plan (DSP) that enables the Commission to review and evaluate the utility's investments in the distribution grid to ensure that they cost-effectively support grid adequacy, reliability and resilience, while simultaneously supporting diversification of energy supply through distributed energy resources, expanding the utilization of non-wire alternatives that may reduce the need for conventional distribution grid investment, and preparing for new expectations upon on the distribution system. These rules should also establish a proactive and transparent process for enhancing understanding of key distribution system characteristics.

3527. Definitions.

The following definitions apply to rules 3525 through 3542. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Ancillary services" means the functions that maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event. Ancillary services include but are not limited to synchronized regulation, contingency reserves, flexibility reserves, voltage and frequency response, power factor corrections, and spinning reserves.

(b) “Capacity need” means a distribution grid capacity constraint or shortfall projected within a ten-year period.

(c) “Demand flexibility” means the ability, often using communication and control technology, to shift electricity use across hours of the day while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality and delivering net benefits to the system, customers, or society.

(d) “Demand response measures” or “demand response” or “DR” means any modulation in customer electric usage at targeted times, including reduction of usage or shifting of usage from one time to another, or interruption or curtailment of electric usage, either with load control equipment or in response to incentives, a signal, or changes in the price of electricity designed to induce changes in electricity use at specific times.

(e) “Direct current fast charger” means a high-power fast charging method of at least 50 kW capacity used to resupply an electric vehicle using direct current electricity, typically 208/480V three-phase.

(f) “Distributed energy resources” or “DER” may include, but are not limited to, distributed generation, energy storage systems, electric vehicles, microgrids, fuel cells, and demand side management measures including energy efficiency, demand response, and demand flexibility that are deployed at the distribution grid level, on either the customer or utility side of the meter. DER can be used to optimize energy use and generation to satisfy the energy, capacity, or ancillary service needs of the distribution grid.

(g) “Distribution system plan” or “DSP” means the compliance plan filed in accordance with rule 3528.

(h) “Energy efficiency measures” are measures that target consumer behavior, equipment, or devices that result in the decrease in electricity usage of customers without detriment to end-use services.

(i) “Grid availability” means the hours per year when the utility makes the grid or a portion of the grid available for use not only by load but also by distributed generation and demand response.

(j) “Grid need” means the need for energy, capacity, ancillary services, reliability, or resiliency services to address a forecasted deficiency on the electric distribution system.

(k) “Hosting capacity” means the amount of distributed generation, including distributed generation paired with battery storage, 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.

(l) “Locational value” means an analysis of distributed energy resources that incorporates location-specific incremental net benefits to the electric grid.

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

(n) "Microgrid" means a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that can act as a single controllable entity with respect to the grid. A microgrid is capable of connecting and disconnecting from the centralized grid to enable the microgrid to operate in both grid-connected or island-mode.

(o) "N-1 event" means an outage event of one distribution or transmission element such as a transformer, feeder, or transmission line that may cause load to shift to other elements as backup. An N-1 event indicates a need for additional reliability capacity if it is determined to cause a potential overload on elements carrying energy to accommodate the event.

(p) "Non-Wires Alternative" or "NWA" means the strategic deployment of distributed energy resources by a utility or a third party and associated control or aggregation of systems and technologies intended to cost-effectively defer or avoid the need for Major Distribution Grid Projects. An NWA is intended to reliably reduce load, congestion or other constraints at times of peak demand in targeted locations on the grid. NWAs can include one or multiple DER, including but not limited to demand response measures, energy efficiency, energy storage, and distributed generation. NWA projects can include these and other investments individually or in combination to meet the specified need.

(q) "Pilot" means a utility offering to test a new use or deployment of DER for a set period of time with a specified end date and number of customers, wherein the utility seeks to gain experience or expertise, and to inform the Commission.

(r) "Program" means an ongoing, long-term offering by the utility with no specified end date that utilizes or deploys DER on the distribution grid in a manner that provides system benefits or cost savings.

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

(t) "Reliability need" means a risk of failure requiring mitigation due to inadequate capacity or voltage support, or an N-1 event on the distribution grid.

(u) "Resilience" is the ability of the distribution grid to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.

3528. Distribution System Plan Filing Requirements.

A utility with over 500,000 customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2022. A utility with 500,000 or fewer customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2023.

(a) Each DSP application filing shall conform to the application requirements contained in rules 3002 and rule 1303 of the Commission's Rules of Practice and Procedure.

(b) Within 30 days of the filing of the application, the Commission shall issue a decision addressing whether the contents of the DSP meet Commission standards based on the information provided by the utility set forth in paragraph 3528(d).

(c) If the DSP identifies major distribution grid projects that meet the NWA suitability screening criteria put forth in paragraph 3534(a), then the DSP proceeding shall consist of two phases.

(I) Within the same proceeding and subject to paragraph 3528(b), the utility shall file a Phase II DSP within 120 days of the filing of the Commission's order establishing the final Phase I DSP. The Phase II DSP shall adhere to the requirements of paragraph 3529(b).

(A) Within 30 days after the filing of the Phase II DSP, parties may submit comments pertaining to the Phase II DSP.

(B) Within 15 days after the deadline for initial comments on the Phase II DSP, parties may submit reply comments.

(d) If the utility claims that any of the requirements set forth in rules 3529 through 3541 are not yet practicable to provide or are currently cost-prohibitive to provide, the utility shall indicate for each requirement:

(I) why the information is not yet practicable or is currently cost-prohibitive, what information could be provided in the alternative and how that alternative information would achieve planning and policy objectives.

(II) how the information could be obtained in future filings, and if so, at what estimated cost, and on what timeframe;

(III) what the benefits or limitations of filing the data in future reports would be as related to achieving the planning and policy objectives; and

(IV) if the information cannot be provided in future reports, what information could be provided in the alternative and how it would achieve planning and policy objectives.

(e) The utility shall file a final DSP action plan in accordance with rule 3536, including all required modifications, within 60 days of the Commission's final decision.

(f) The utility may file, at any time, an application to amend the contents of a DSP approved pursuant to paragraph 3536(c). Such an application shall meet the requirements of paragraphs 3002(b) and 3002(c), shall identify each proposed amendment, shall state the reason for each proposed amendment, and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

(g) Utilities are encouraged to convene regular, informal stakeholder meetings to discuss DSP-related issues and to inform the contents of DSP applications. The utility shall convene at least one stakeholder meeting at least 90 days prior to the filing of the DSP. As part of these

stakeholder meetings, the utility shall solicit input on future programs and/or pilots and solicit feedback on both the hosting capacity analysis and the web portal. The utility shall make all reasonable efforts to engage local governments and community organizations representing disproportionately impacted communities. The Commission may, at its discretion, require utilities to host stakeholder discussions regarding specific DSP topics.

3529. Contents of the Distribution System Plan.

(a) The utility shall file a Phase I DSP with the Commission that contains the information specified below. When required by the Commission, the utility shall provide any relevant studies, additional data, and work-papers to support the information contained in the plan. The DSP shall include the following:

(I) 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;

(II) a description of how the distribution grid may evolve over the next five and ten years due to various factors, such as increasing DER penetration, the expansion of beneficial electrification programs and other electrification, advanced metering infrastructure, increasing demand flexibility, energy efficiency and other emerging technologies. The utility should discuss the challenges and opportunities presented by the emergence of new technology as well as plans they have to adapt to or utilize these changes to the grid;

(III) 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;

(IV) distribution system forecasts, as described in rule 3530;

(V) an assessment of the existing distribution system, as described in rule 3531;

(VI) an assessment of grid needs, as described in rule 3532;

(VII) a description of grid innovations and any proposed pilots and programs, as described in rule 3533;

(VIII) NWA suitability screening results, as described in paragraph 3534;

(IX) a proposed NWA cost benefit analysis methodology, as described in paragraph 3535;

(X) a Phase I action plan, as described in subparagraph 3536;

(XI) a proposal for cost recovery, which may include an incentive, as described in rule 3538;

(XII) a security assessment, as described in rule 3539.

(XIII) a proposal for implementation of a web portal as described in paragraph 3541(d);

(XIV) a description of the stakeholder engagement process, as described in paragraph 3528(g); and

(XV) 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.

3530. Distribution System Forecasts.

(a) Forecast requirements. The utility shall prepare energy and demand forecasts for each year within the ten-year planning period. The utility shall also prepare ten-year forecasts for load growth on the distribution grid, including the growth of various types of DERs connected to the distribution grid. Forecasts should be based on at least two growth scenarios (State Policy and High), including 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. Forecasted growth should include the following:

(I) peak load growth at each substation, by year;

(II) peak load growth at each substation transformer by year;

(III) peak load growth on each feeder, by year;

(IV) coincident peak and non-coincident peak load growth at substations, transformers, and feeders, by voltage class;

(V) load growth associated with beneficial electrification, by substation transformer and by feeder under each scenario in subparagraph 3530(a)(X);

(VI) load growth due to new planned neighborhoods or housing developments,

(VII) net load impacts due to DER adoption under each scenario in subparagraph 3530(a)(X);

(VIII) net load impacts due to demand side management, demand response, and demand flexibility;

(IX) approved CSG capacity in RES Plans and anticipated CSG capacity additions beyond the current effective RES plans;

(X) forecasts of DERs and NWA should include ten-year scenarios that project expected growth of DERs and NWA, including expected geographic dispersion at the distribution feeder level and impacts on distribution planning. Scenarios shall be designed to meet or exceed current state policy such as those related to greenhouse gas (GHG) reductions, increased use of DERs, electrification, distribution reliability, resiliency, and transmission system needs. Scenarios shall include key inputs including growth of peak exported generation from distributed solar generation; growth of peak exported generation from distributed battery storage systems; and growth of peak exported generation from all other distributed generation. Scenarios shall be based on the following criteria:

(A) State Policy Goal Scenario: Adopts a current forecast case for DER and NWA deployment for distribution planning at the feeder lever, down to each line section, assuming compliance with current state policy goals.

(B) High Growth Scenario: Adopts a high growth case for DERs. This scenario should exceed state policy goals, which may include long-term GHG reductions, and beneficial electrification at levels higher or faster than required in state statute or incurrent state policy goals. Additionally, the High Growth Scenario may improve upon performance in areas of demand flexibility, distribution reliability, resiliency, and transmission system needs beyond a business as usual projection.

(b) The utility shall provide all assumptions and methodologies that are inputs into the forecasting scenarios in paragraph 3530(a).

3531. Assessment of Existing Distribution System.

(a) System overview and substation historical data.

(I) To identify and assess needs on the distribution system, each utility shall provide a map of existing and planned substations within its service territory, as well as tabular information about the current design capacity, and performance of each substation and substation transformer. The assessment should also include the status of advanced infrastructure deployment which may be made by reference to other reports or filings. At a minimum, this should include the following information for each substation and substation transformer on the utility's distribution grid:

(A) maximum rated capacity of each substation transformer;

(B) peak hourly demand on each substation transformer for the past three years;

(C) capacity margin for each substation transformer;

(D) advanced functionality capabilities of each substation transformer;

(E) number of feeders served by each substation and substation transformer;

(F) maximum rated capacity of each feeder;

(G) peak hourly demand on each feeder for the past three years;

(H) capacity margin for each feeder;

(I) percentage of grid availability;

(J) minimum daytime load;

(K) aggregate miles of underground and overhead wires, categorized by voltage class;

(L) monitoring capabilities and data collection on the distribution system, such as the substations and feeders for which the utility has real-time supervisory control and data acquisition (SCADA) capability;

(M) amount of distributed generation installed on the system (number of systems and nameplate capacity in kilowatts (kW) by generator types, organized by substation or feeder);

(N) description of NWA on the system, organized by substation or feeder; including annual cost savings and greenhouse gas emissions reductions;

(O) amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours (kW and kWh));

(P) estimated number of EVs and Level 2 and DCFC EV charging stations organized by substation or feeder;

(Q) estimated demand flexibility capacity on the system and historic utilization of those flexibility capabilities;

(R) voltage and power quality data for the past three years; and

(S) location of highly seasonal circuits as defined by subparagraph 3667(a)(IV).

(II) Hosting capacity analysis.

(A) As part of its DSP, each utility shall develop a hosting capacity analysis of the distribution system.

(B) The analysis shall determine the hosting capacity on a particular feeder, feeder section or substation at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

(C) The hosting capacity analysis shall be performed using a load flow analysis and forecasted distribution facilities and their capacity, configuration, loading, and voltage data gathered at the substation, feeder, and primary node levels where available.

(D) The utility shall perform scenario analysis to evaluate hosting capacity need under normal and planned and unplanned contingency conditions, as well as under the High Growth scenario.

(E) The utility shall provide a detailed description of the methods and outcomes it used to perform the hosting capacity analysis.

(F) The hosting capacity analysis shall reflect that which appears in the web portal as described in rule 3541. The utility shall also provide a detailed narrative describing the utility's progress towards advancements to the accuracy and value of the hosting capacity analysis and providing real-time hosting capacity data. This should include a description of how its hosting capacity analysis currently advances customer-sited DER (in particular distributed renewable electric generation and energy storage systems), how the utility anticipates the hosting capacity analysis will aid in identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which the utility anticipates customer benefit stemming from the hosting capacity analysis.

(G) For their first DSP filing, utilities with 500,000 or fewer customers shall provide an Excel spreadsheet (or equivalent format) by feeder of either daily daytime minimum load or, if daytime minimum load is not available, daily peak load with the time granularity specified.

3532. Grid Needs Assessment.

(a) The utility shall provide a summary analysis of the energy, capacity, ancillary services, and reliability needs and constraints on a utility's distribution system and solutions to those needs.

(b) The grid needs assessment shall include an analysis regarding the suitability of non-wires alternatives to mitigate identified needs and recommendations for the deployment of utility infrastructure upgrade solutions versus the procurement of non-wires alternative solutions to address any identified needs.

(c) The grid needs assessment shall address existing and forecasted needs over a ten-year planning period that could result in a major distribution grid project.

(d) The grid needs assessment shall include each of the following parts.

(I) An assessment of critical needs.

(A) The utility shall provide an assessment of critical capacity and reliability needs that must be addressed within the ten-year planning horizon.

(B) The assessment shall include a review of all planned, proposed and potential major distribution grid projects which will be required to address constraints related to substation transformers and feeders that are forecasted to have insufficient capacity to adequately serve peak load or reliability needs over the next ten years.

(C) The assessment shall be divided into two parts – one detailing short-term needs within zero to three years, and one detailing longer-term needs in four to ten years.

(D) The data used for the assessment shall be provided in megawatt values in tables, in a logical spreadsheet form (both printed and functional Excel spreadsheet formats) and graphically as a map in executable ARC GIS or similar format.

(E) The assessment of critical needs will be provided via the web portal, described in rule 3541. Any notable updates to the web portal should also be made in this section of the DSP.

(F) The assessment shall include a review of the capability of the distribution system and any needs incurred to interconnect approved CSG capacity in the utility's current SGIP queue, the capacity approved in its most recent RES Plan but not yet acquired, and a reasonable expectation of future CSG capacity during the DSP planning period.

(II) Exemptions for short-term planning needs.

(A) For any grid needs identified during the current planning cycle, which require service within thirty-six months, the utility shall be exempt from the rules governing solicitations for Major Distribution and Transmission Grid projects - ule 3537. As part of its assessment, the utility shall explain why this grid need was not previously identified.

(III) The utility's current distribution plan for distribution grid investments, as well as the total capital budget including the past three years and the next five years of projected budget. Budgets shall be broken down by relevant budget categories.

(IV) Fast charging locations for electric vehicles. The utility shall use the results of the grid needs assessment to identify locations where substation transformers and feeders have sufficient capacity for hosting multiple direct current fast chargers for electric vehicles. Utilities will also assess vehicle-to-grid (V2G) opportunities as potential NWA projects.

(V) An identification of any long-term needs identified in the grid needs assessment for which ratable procurement may avoid or defer the anticipated need driven by steady load growth, including geographically targeted deployment of demand flexibility, demand response, and energy efficiency measures.

3533. Grid Innovation.

(a) The DSP shall address DSP pilots and programs that are either in progress, planned, or have been suggested by other parties and found to have merit by the utility. The DSP shall identify any barriers to deployment of DERs and NWA. Such barriers may include but not be limited to integration or interconnection of DERs and NWAs, barriers that limit the ability of a DER and NWA to provide benefits, and barriers related to distribution system operation and infrastructure capability. This section shall include, but not be limited to:

(I) Within each DSP, the utility may propose new pilots and programs designed to gain experience integrating DER, NWA or other new distribution technologies in a way that improves system performance, minimizes system costs, increases system resiliency and/or reliability, and/or reduces greenhouse gas emissions including from reduced curtailment of renewable energy. Such pilots and programs may be proposed as solutions to help solve identified grid needs identified under rule 3532.

(II) New proposed pilots. Within each DSP, the utility may propose new pilots. Pilots shall not be required to pass a cost-benefit test; however, the Commission shall determine that the pilot can be implemented at a reasonable cost and rate impact. Each of the proposed pilots shall, at a minimum, include:

(A) a description of what the utility seeks to learn through the pilot with specific goals and metrics;

(B) an explanation of how the pilot can be scaled to enable the utility to achieve objectives described in the plan pursuant to rule 3529;

(C) the specific DER and NWA technology or technologies eligible for the pilot, including any operational requirements;

(D) a description of any geographic or locational focus of the pilot;

(E) the customer classes that may participate in the pilot;

(F) a description of the potential benefits the utility expects the pilot technology to demonstrate;

(G) a description of the costs of the pilot, including a cap on costs for each pilot;

(H) criteria for evaluation of the pilot and an evaluation plan that includes a calculation of pilot costs, schedule, and a summary of pilot benefits, including quantified benefits, as available;

(I) a description of the use of any targeted incentive payments, or other incentives, provided to participants;

(J) a description of the mechanism to acquire equipment, technologies, vendors, and participants in the pilot; and

(K) a description of how the pilot will provide health, safety, environmental, or financial benefits to disproportionately impacted communities.

(III) New proposed programs. Within its DSP, the utility may seek approval for a new program to better integrate DER and NWA or other distribution technologies into its business practices in a way that improves system performance, minimizes costs, increases system resiliency and reliability, or reduces emissions. Proposed programs may be successors of completed pilots; however, a utility does not need to have conducted a pilot in order to seek approval for a new program.

(IV) The utility may propose pilots or programs developed internally and shall also accept third-party proposals for pilots and programs at any time. For a third-party pilot or program to be considered in a DSP, it must be received by the utility at least six months prior to the DSP filing deadline. 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. For any proposal not considered, the utility shall explain why it was not considered.

(V) Updates on existing pilots and programs. Within its DSP, the utility shall provide a narrative status update on all active pilots and programs approved in prior DSPs. The utility may also seek reauthorization of existing programs within a DSP. As part of its first DSP, the utility is encouraged to evaluate whether any existing reporting obligations outside the DSP related to distribution system pilots, programs, or projects should be centralized within the DSP process. Upon Commission approval, and notice filed within the original proceeding, such reporting obligations shall be transferred to DSP proceedings.

(b) NWAs and pilots may include the use of targeted incentive payments to encourage DER adoption or optimize the use of existing DERs by customers in specific locations, to provide locational value to the system. Such incentives shall be accounted for in the cost benefit analysis as described in rule 3535 and shall be recovered in a manner similar to other distribution-grid related expenditures.

3534. NWA Suitability Screening.

(a) Major distribution grid projects identified to be necessary in the grid needs assessment conducted pursuant to rule 3532 shall be subject to an NWA suitability screening to determine if a NWA may be a suitable alternative to traditional utility infrastructure solutions.

(b) The NWA suitability screening is performed by the utility and includes the following criteria:

(I) the project is anticipated to occur during the ten-year planning horizon;

(II) the constraint is due to thermal loading, voltage, capacity or reliability issues and could be resolved by a DER, a reduction in peak demand loading, a reduction in energy consumption, or load shifting on the transmission or distribution facilities; and

(III) the conventional solution is still within the planning or design stage, with no major equipment on order, received, or installed that cannot be repurposed for other uses.

(IV) A utility may request that projects such as wildfire mitigation, relocations, and asset health and renewal projects may be excluded from suitability screening. Such requests should be substantiated to show why the NWA suitability screening is not possible or could not reasonably result in an alternative to traditional utility infrastructure.

(c) The utility may seek a waiver from these requirements on a case-by-case basis if necessary, to preserve reliability, serve economic development needs, or to meet other unforeseen circumstances where a non-wires alternative cannot provide the planning constraint.

(d) For all major distribution grid projects identified as meeting all of the NWA suitability screening, the utility shall conduct a technology-neutral competitive solicitation for NWAs to defer, reduce, or avoid the costs of the major distribution grid projects.

3535. NWA Cost Benefit Analysis.

(a) In order to assess the cost-effectiveness of a potential NWA solution that meets the NWA Suitability Screening in rule 3534, the utility shall:

(I) develop and publish a cost benefit methodology that will be provided in the utility's DSP;

(II) assess the proposed NWA solution using a cost-benefit methodology that considers the approach as put forward in the National Standard Practice Manual and specifically including the following costs and benefits: avoided or deferred costs associated with an NWA solution, sub-transmission, substation transformer additions or upgrades, feeder capital and operating costs, distribution power quality equipment, reliability and resiliency costs, energy and capacity value of generation, capacity value of storage, greenhouse gas emissions including the Commission approved social cost of carbon useful life of NWA and traditional solutions, and dispatchability and availability of the technology. If the utility is proposing a performance incentive as part of cost recovery for the NWA pursuant to paragraph 3538(d), it shall include the cost-benefit analysis both with and without the performance incentive included as a cost of the project;

(III) provide a description of DSP goals, compliance with statute, rules, and requirements, and additional relevant principles; and

(IV) assess the proposed distribution system costs, direct system benefits, indirect system benefits, and system sensitivity analysis.

(b) The utility may also propose an alternative or adjusted cost-benefit methodology if it does not believe that the full costs and benefits of the NWA solution are being counted.

3536. Action Plan.

(a) The utility shall provide a five-year action plan for distribution system investments and activities within its Phase I DSP which will serve as an application report for the Commission and stakeholders to rely upon when evaluating distribution system planning projects, pilots, and programs.

(b) The Phase I action plan shall include the sequence of events and timelines for each action that will not require a solicitation process following Phase I, including:

(I) the implementation of NWAs identified through the NWA cost benefit analysis process;

(II) the implementation of proposed pilots and programs as specified in rule 3533;

(III) the implementation of major distribution grid projects that were determined to be the best option to address grid needs;

(IV) system interoperability and communications strategy;

(V) costs and plans associated with obtaining data necessary for the evaluation of NWAs, pilots and programs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles);

(VI) interaction of planned or proposed investments with other utility programs and the effects on existing utility programs and tariffs; and

(VII) the implementation of major distribution projects intended to cost-effectively interconnect the approved and reasonably forecasted CSG capacity, including that approved by RES Plans in effect during the planning period;

(c) Subject to paragraph 3528(b), the utility shall provide an updated action plan with its Phase II DSP. This plan shall include the sequence of events and timelines for NWAs identified in the solicitation process, including:

(I) the implementation of NWAs identified through the NWA analysis process;

(II) an updated system interoperability and communications strategy;

(III) costs and plans associated with obtaining data necessary for the evaluation of NWAs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles); and

(IV) interaction of planned or proposed NWA investments with other utility programs and the effects on existing utility programs and tariffs.

3537. NWA Solicitation Process (Phase II).

(a) The utility shall propose in its DSP (Phase I) Application appropriate timelines for the release of the RFP(s), the receipt of bids, evaluation of bids, the utility's proposal to the Commission, the filing of the independent evaluator report, party comments in response to the independent evaluator report, and the Commission decision. These timelines should consider similar timelines as expressed in the Electric Resource Planning Rules, specifically rule 3613. The timelines proposed by the utility and approved by the Commission in the DSP (Phase I) shall describe an appropriately expedited, comment-based NWA Solicitation Process (Phase II) to facilitate timely decisions and implementation of NWA bids.

(b) For projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria, an Independent Evaluator (IE) shall be retained.

(I) The utility shall file for Commission approval the name of the independent evaluator. The Commission shall approve an independent evaluator by written decision during Phase I.

(II) The utility shall pay for the services provided by the independent evaluator pursuant to a contract approved by the Commission. The terms of such contract shall prohibit the independent evaluator from assisting any entity making proposals to the utility for subsequent resource acquisitions for three years.

(III) The utility shall work cooperatively with the independent evaluator and shall provide the independent evaluator immediate and continuing access to all documents and data reviewed, used, or produced by the utility in the preparation of its projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria and in its bid solicitation, evaluation, and selection processes. The utility shall make available the appropriate utility staff to meet with the independent evaluator to answer questions and, if necessary, discuss the prosecution of work. The utility shall provide to the independent evaluator, in a timely manner so as to facilitate the deadlines outlined in these rules, bid evaluation results and modeling runs so that the independent evaluator can verify these results and can investigate options that the utility did not consider. If the independent evaluator notes a problem or a deficiency in the bid evaluation process, the independent evaluator should notify the utility.

(IV) All parties in the DSP proceeding other than the utility are restricted from initiating contacts with the independent evaluator. The independent evaluator may initiate contact with the utility and other parties. For all contacts with parties in the DSP proceeding, including those with the utility, the independent evaluator shall maintain a log that briefly identifies the entities communicating with the independent evaluator, the date and duration of the communication, the means of communication, the topics discussed, and the materials exchanged, if any.

(V) The independent evaluator shall generally serve as an advisor to the Commission and shall generally not be a party to the proceedings. As such, the independent evaluator shall not be subject to discovery and cross-examination at hearing.

(VI) Within 30 days of a utility selecting an NWA bidder to advance to Phase II, the independent evaluator shall file a report. The independent evaluator shall address in its report whether the utility's competitive acquisition procedures and bidding policy, including the assumptions, criteria and models, were sufficient to solicit and evaluate bids in a fair and reasonable manner, with any deficiencies specifically noted. The independent evaluator shall provide confidential versions of these reports to Commission staff and the OCC.

(c) All solicitations, unless requested by the Commission, or requested by the utility and approved by the Commission, shall be conducted in a technology neutral manner.

(d) The utility may require prospective bidders to sign non-disclosure agreements in order to obtain information deemed confidential or highly confidential.

(e) After final NWA bids have been selected by the utility, the utility shall update the elements of the Action Plan that pertain to NWAs.

3538. Approvals and Cost Recovery.

(a) The utility may seek Commission approval of a NWA, pilot, or program in its DSP application filing. Should such an approval be sought, the Commission may require a hearing specifically on the NWA pilot, or program in addition to the process described in rule 3536. The Commission may require the utility to demonstrate satisfactory compliance with appropriate benchmarks or performance metrics outlined in the Commission's decision approving pilots, programs or NWA or other components of the DSP. Utilities may seek approval to implement an NWA, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation. New pilots or programs should meet the standards and requirements set forth in paragraph 3533(a).

(b) A utility may seek any necessary approvals for a NWA, pilot or program pursuant to an approved DSP in other proceedings, including, but not limited to:

(I) demand side management planning;

(II) renewable energy standard compliance planning;

(III) transportation electrification planning; or

(IV) innovative technology pilot programs or demonstrations;

(c) 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. 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 reasonable. The utility may seek approval to implement NWAs, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation.

(d) In the application for approval of a DSP, the utility shall address how it anticipates recovering costs associated with the investments put forward in its DSP in accordance with subparagraph 3529(a)(XI).

(I) Investments made to implement an approved DSP shall be deemed to made in the ordinary course of business and shall be recovered through the normal implementation of the utilities rate mechanisms.

(II) The utility shall demonstrate that the investments made to implement an approved DSP do not undermine equitable access to other utility programs and do not materially impact the related utility program's targeted performance.

(III) The utility may propose a performance incentive for implementing any NWA, pilot, or program as a component of its cost recovery proposal. The performance mechanism, if proposed, shall also be included as part of the cost-benefit analysis specified in rule 3535. A performance incentive may include allocating to the utility a share of the cost-savings derived from NWA implementation as compared to the avoided capital investment.

(IV) For costs the Commission deems to be incurred outside the ordinary course of business, the utility may seek approval of a regulatory asset for recovery as part of the utility's next rate case, or may be placed in another cost recovery mechanism as proposed by the utility. The Commission shall establish the authorized rate of return on any regulatory asset created pursuant to this paragraph.

(e) 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.

(f) The utility shall file a final DSP, which may include required modifications, within 60 days of the Commission's final decision.

3539. Security Assessment.

(a) The utility shall provide a narrative assessment of the reliability and resilience of the distribution grid with respect to cybersecurity and physical security, including:

(I) current status of distribution grid reliability and plans for improving reliability, including areas of the grid where reliability problems have been identified, with plans for resolving them. Distribution grid reliability metrics (SAIDI and SAIFI at a minimum) should be provided for each year for the past three years for each substation;

(II) list of major outages, including cause and duration, involving 10,000 customers or more for each year for the past three years;

(III) analysis of cyber security issues or other threats to the distribution system and what efforts the utility is taking to ensure the distribution system is secure;

(IV) analysis of risks by substation posed by natural disasters such as wildfires, floods, severe storms, and a detailed description of efforts the utility is taking to increase system resiliency in the response to these risks;

(V) other plans aimed at improving distribution system resiliency; and

(VI) any pilots or programs, existing or proposed, aimed at increasing reliability and resiliency, using microgrids or other technology, should be discussed within the Grid Innovation section of the Phase I DSP, as described in rule 3533.

(VII) The utility may incorporate by reference any other filings or applications made to the Commission that are relevant to a discussion of distribution system reliability and resilience.

3540. Data Access, Privacy and Confidentiality.

(a) The utility shall disclose data necessary to implement these rules with appropriate levels of protection, considering sensitivity and public benefit. The utility shall identify and address the treatment of sensitive information in consideration of the objectives of DSP and as required by these rules.

(b) The utility shall not disclose personal information, as defined in paragraph 1004(x), or customer data, as defined in paragraph 3001(i). paragraph 3033(b) shall not apply to data releases under this rule.

(c) In each DSP application filing made pursuant to rule 3529, the utility shall file a list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information that the utility claims is highly confidential, and its proposed treatment of the information. For good cause shown the utility may seek to protect information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

3541. Web Portal.

(a) The utility shall make available a web portal that provide map-based and tabular data that is publicly available or access-restricted as further defined under this rule. Such web portal shall be designed to meet the objectives of the DSP and shall allow users to download data in tabular and geospatial formats

(b) The utility may not deny access to its web portal. To ensure the appropriate level of protection of sensitive information, the utility may require visitors to the web portal to take actions, including

(I) requiring visitors to acknowledge terms of service associated with its use, provided those terms do not preclude academic or public policy purposes; and

(II) establishing registration processes, including the creation of a username and password, and/or the use of multifactor authentication for access to sensitive information.

(c) A web portal shall include at least the following information:

(I) consistent with subparagraph 3531(a)(II), the utility's hosting capacity analysis;

(II) publicly available summaries, data, or links to existing information on the utility's website related to programs approved by the Commission that address the deployment of DERs, including, without limitation, pilots, tariffs, and incentives; and

(III) any additional content as directed by the Commission.

(d) Implementation of the web portal.

(I) Prior to filing its first DSP application pursuant to rule 3529, the utility shall engage potential users of the web portal from multiple sectors to develop a proposal for implementation of the web portal to be filed with the application.

(II) In its first DSP application pursuant to rule 3529, the utility shall present a proposal and timeline for developing a web portal that meets the requirements of this rule and includes:

(A) a summary of its process for identifying and engaging potential users of the web portal and the results of that process;

(B) a description of use cases that will be implemented through the web portal to meet the objectives of DSP;

(C) an evaluation of the data required in a DSP application pursuant to rule 3529 that addresses what data will be provided on the web portal and at what level of granularity, an evaluation of the risks and benefits associated with providing such data, proposals for treatment of sensitive information, and identifying any data for which confidential or highly confidential treatment is sought under the process provided in paragraph 3540(c);

(D) a proposal for providing functionalities that enhance the user experience, such as color-coding of substations, circuits, and feeders or ability to change the year of the data being displayed;

(E) a proposal for what information is currently available and can be provided on a web portal and what information requires approval by the Commission for incorporation onto a web portal;

(F) a proposal for updating data provided through the web portal, specifically addressing the quarterly updating of the utility's hosting capacity analysis as described in subparagraph 3531(a)(II);

(G) a proposal for enabling Application Programming Interface (API) capabilities where reasonable and appropriate; and

(H) a proposal for collecting user feedback on an ongoing basis.

(III) In subsequent DSP application proceedings, the utility shall provide an update on the status of implementing the web portal and any proposed changes to functionality and treatment of data. Prior to each application pursuant to rule 3529, the utility is encouraged to engage with stakeholders including users of the web portal, to identify changes.

(IV) The utility shall file an annual compliance report in the most recent DSP application proceeding that provides an update on the status of implementing the web portal, summarizes user feedback, and describes how the utility addressed that feedback, including any updates or revisions to the functionality of the web portal that are anticipated to occur prior to its next DSP application filing.

3542. Evaluation and Reporting.

(a) An assessment of the existing distribution system, as described in rule 3531.

(b) An assessment of Distribution Grid Security as described in rule 3539.

(c) Starting with its second DSP application, the utility shall describe the 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.

(d) The utility shall report lessons learned from the DSP process and identify ways to improve methodologies through research before the next filing.

3543. – 3549. [Reserved].

Decision No. C21-0549

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 20R-0516E

IN THE MATTER OF THE PROPOSED AMENDMENTS TO RULES REGULATING ELECTRIC UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-3, RELATING TO DISTRIBUTION SYSTEM PLANNING.

DECISION ADDRESSING EXCEPTIONS TO DECISION NO. R21-0287 AND ADOPTING RULES

Mailed Date: September 7, 2021
Adopted Date: August 25, 2021

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I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Public Utilities Commission (Commission or PUC) grants, in part, and denies, in part the exceptions filed on July 28, 2021 to Decision No. R21-0287, issued July 8, 2021, by Hearing Commissioner Megan Gilman (Recommended Decision). The Commission adopts revised rules governing Distribution System Planning (DSP Rules), located within the Commission's Rules Regulating Electric Utilities, 4 *Code of*

Colorado Regulations (CCR) 723-3 (Electric Rules). The adopted DSP Rules are attached to this Decision in legislative format (*i.e.*, strikeout/underline) as Attachment A, and in final format as Attachment B.

B. Background

2. On December 3, 2020, the Commission issued a Notice of Proposed Rulemaking (NOPR) to amend the Commission's Electric Rules. The proposed amendments develop these new rules regarding DSP.[1] The Commission noticed the proposed rules, provided with Decision No. C20-0837, available to the public through the Commission's Electronic Filings system.

3. This rulemaking satisfies the requirements of Senate Bill (SB) 19-236, codified at § 40-2-132, C.R.S., requiring the Commission to adopt rules regarding DSP. Specifically, SB 19-236 directs the Commission to promulgate rules establishing, for the first time, that utilities must file Distribution System Plans (DSPs) and evaluate Non-Wires Alternatives (NWA). Section 40-2-132, C.R.S., also provides that the Commission may adopt criteria, benchmarks, or accountability mechanisms to evaluate the success of any NWA investment authorized pursuant to a DSP.

4. The Commission has developed these proposed rules to enhance transparency and accountability in the DSP process. The Commission determined that to be an effective tool, a DSP needs to be comprehensive in terms of examining the entire grid and all the potential options for improving the grid from a reliability, resilience, and cost effectiveness standpoint. We stress that utilities must also enable the safe and timely interconnection of Distributed Energy Resources (DERs) by customers and third parties and strive to optimize the use of new

[1] Decision No. C20-0837 (issued on December 3, 2020).

resources, NWAs, and emerging grid technologies, while reasonably balancing the risks and opportunities.

5. The NOPR adopted a schedule for filing comments and invited interested participants to file initial comments no later than January 29, 2021, and to file reply comments no later than February 19, 2021. A public rulemaking hearing was scheduled for March 11 and 12, 2021. The Commission referred this matter to Hearing Commissioner Megan Gilman to preside over rulemaking hearings and for the issuance of a recommended decision.[2]

6. On January 29, 2021, initial comments were filed by the City and County of Denver (Denver); the Colorado Energy Office (CEO); Tri-State Generation and Transmission Association, Inc.; the Advanced Energy Economy Institute (AEEI); Western Resource Advocates (WRA); the Colorado Solar and Storage Association and the Solar Energy Industries Association (COSSA/SEIA); Southwest Energy Efficiency Project (SWEEP); Black Hills Colorado Electric, LLC (Black Hills); the Colorado Office of Consumer Utility Advocate (OCA); the Colorado Energy Consumers Group (CEC); Karey Christ-Janer; Public Service Company of Colorado (Public Service or Company); and on February 5, 2021 by the City of Boulder (Boulder).

7. On February 19, 2021, reply comments were filed by CEO, AEEI, WRA, OCA, CEC, Public Service, SWEEP, COSSA/SEIA, Black Hills, SunShare, LLC (SunShare), and WRA.

8. A public comment hearing was held on March 11, 2021.

[2] Decision No. C21-0108-I issued February 26, 2021, Ordering Paragraph II.A.1 at page 1.

9. On April 9, 2021, Closing Comments were filed by Boulder. On April 16, 2021, post-hearing comments were filed individually by WRA, CEC, Black Hills, Karey Christ-Janer, Denver, COSSA/SEIA, Public Service, and Joint Post-Hearing comments and redline rules were filed by AEEI, CEO, and COSSA/SEIA (the Joint Stakeholders).

10. Additional written comments were filed on April 27, 2021 by COSSA/SEIA, April 29, 2021 by Black Hills, and May 7, 2021 by Public Service.

11. On July 8, 2021, Hearing Commissioner Gilman issued Recommended Decision No. R21-0387, which is the subject of this Decision.

12. On July 28, 2021, the following rulemaking participants filed exceptions to the Recommended Decision: Public Service, Black Hills, WRA and CEO (together WRA/CEO), and COSSA/SEIA.

13. On August 11, 2021, the following rulemaking participants filed responses to the exceptions: Public Service, Black Hills, WRA/CEO, COSSA/SEIA, SunShare, and AEEI.

C. Exceptions to Recommended Decision

14. Below, we address the exceptions filed to the Recommended Decision, any responses, and the Commission's findings and conclusions granting or denying the exceptions.

1. Rule 3526 - Overview and Purpose

15. This rule summarizes the general purpose of a DSP proceeding. The Recommended Decision added language stressing the importance of transparency and the timely sharing of information as key aspects of the distribution system, as increased information-sharing is an important part of developing NWA solutions and DER deployment in line with State policy directives.

a. Exceptions

16. WRA/CEO express concern that Rule 3526 does not include any reference to State policy. WRA/CEO maintain that a key purpose of the DSP Rules is to enable the Commission to review and evaluate whether proposed distribution system investments support progress toward reaching related State policy goals, including greenhouse gas (GHG) emission reductions, beneficial electrification, and transportation electrification. WRA/CEO further argue that if a Commission modifies a DSP specifically to achieve State policy goals, then it follows that supporting State policy goals is a fundamental purpose of DSP. WRA/CEO provides edits to recommended Rule 3526 to reference specific State policy goals and corrects a minor typographical error.

b. Responses

17. Public Service disagrees with WRA/CEO's recommendation to broaden Rule 3526 to reflect the inclusion of State policy goals, and recommends that the Rule remain the same. The Company is concerned that proposals to embed specific non-legislative policy elements into Commission Rules go beyond the Commission's statutory directive of Colorado Public Utilities Law. Public Service adds that there is also an equity and cost-effectiveness consideration related to pursuing goals. For example, if the Company makes investments well beyond current mandates and orders, customers may feel the cost impact of these investments without having a corresponding level of benefits.

c. Findings and Conclusions

18. We agree with both WRA/CEO and Public Service. Overall, we believe the overview and purpose section as proposed in the Recommended Decision is appropriate as it addresses the specific issues that these rules are supposed to achieve. We do agree with

WRA/CEO that the Commission will look at a DSP to enable the utilities to achieve State policies.

19. However, as Public Service discusses in its response, adding generalized statements regarding non-legislative policy may not be the best approach and does not add specific benefits to this section. We also agree with Public Service's contention that policy aspirations can and do change over time. While it is important to have aspirational goals, those policy discussions can occur in individual proceedings, but they should not be hardwired into Commission Rules.

20. We thus modify the proposed language for Rule 3526 that states a DSP will ensure progress toward priorities highlighted by State legislation. Accordingly, we adopt modified language that refers to legislative priorities, finding this to be a sufficient compromise between the request to reference State policies and the request to avoid such references to promote flexibility.

2. <u>Rule 3527 - Definitions</u>

21. The Recommended Decision adopts several changes to 3527(c) "Demand Flexibility" for improved clarity and adjusts the definition to indicate that demand flexibility often includes communication or control technology, rather than in every situation.

22. The Decision also adopted the proposed definition from the Joint Stakeholders (AEEI, CEO, COSSA/SEIA, SWEEP, and WRA) for 3572(i) "Grid Availability" to help enable reporting on the availability of the grid as it applies not only to load but also to customer-side resources, such as distributed generation and demand response. They state that the goal of adding this definition, as well as the related reporting requirement in Rule 3531, is

to help ensure that the grid remains available as much as possible and customer-side resources do not face unnecessary outages.

a. Exceptions

23. Public Service believes the definitions of (c) "Demand Flexibility" and (d) "Demand Response" could be combined under a single, more expansive definition per Rule 3527 as currently there is significant overlap between the two definitions and functionally these definitions are intended to achieve the same outcomes (a shift or reduction in demand). If both definitions are retained in final rules, the Company requests additional specificity and demonstration of the differences between the two terms in order to meet the reporting required by Rule 3530(a)(VIII) and Rule 3531(a)(I)(Q).

24. Black Hills also seeks clarification of the definition of "Demand Flexibility" as they argue its definition is redundant and overlaps with the definition of "Demand Response."

25. Regarding (i) "Grid Availability," Public Service argues that several participants in this Proceeding seem to imply that the utilities have discretion as to when and how the grid is "available" to load and/or DERs. Public Service notes it does not arbitrarily make the grid unavailable to these customer or asset types and argues that "unavailability" of the grid for customer loads is already captured in the Company's reliability reporting through metrics like SAIDI, SAIFI, and CAIDI. Based upon the limited discussion and explanation of Grid Availability, Public Service believes this concept is captured under the Company's obligation to serve, and, for DER customers, contractually under the Company's interconnection agreement process and Small Generation Interconnection Application.

26. Black Hills states in its exceptions that it does not understand how the Commission intends for the Company to assess hours in which it has made the grid available

for use. Black Hills states it does not "make the grid or a portion of the grid available for use."[3] Black Hills adds that it manages the physics by ensuring appropriate levels of energy are available to serve customer demands. More specifically, Black Hills states it manages voltage levels within acceptable ranges to ensure reliable service. Black Hills suggests either further clarifying the intent of the definition or deleting it outright.

27. Public Service argues that expanding the definition of (k) "Hosting Capacity Analysis" (HCA) to include paired battery energy storage systems makes the analysis significantly more complex given that the battery energy storage systems must be modeled as both load and generation, which can be operated in several different configurations. Public Service explains that its current hosting capacity software tool is unable to model this level of complexity, and the Company is unaware of any software solution capable of doing so.

b. Responses

28. Responding to the utilities' concerns regarding "Demand Flexibility," WRA/CEO state that Public Service's proposed definition does not capture the full spectrum of demand flexibility opportunities that utilities can implement, arguing that the amendments significantly and unnecessarily narrow the concept of demand flexibility to only reducing peak demand. WRA/CEO believe demand flexibility is far broader than solely peak load reduction, stating it can also serve other purposes such as the shifting of load to avoid renewable curtailment or minimize GHG emissions. WRA/CEO add that while demand flexibility and demand response are often used simultaneously, recommended Rules 3529(a)(II) and 3531(a)(I)(Q) only include demand flexibility. They offer clarifying amendments to the proposed definition.

[3] Black Hills' Exceptions at p. 7.

29. AEEI also urges the Commission to retain 3527(c), because they argue demand flexibility is capable of performing multiple functions that provide grid benefits.

30. COSSA/SEIA respond to the utilities' exceptions on "Grid Availability," stating that the Commission should retain this definition to capture data about the availability of the grid not just to load, but to distributed generation. COSSA/SEIA argue that the objective of requiring the utilities to report on grid availability is to enable the Commission and the public to track trends with respect to the availability of the grid to distributed generation in particular. COSSA/SEIA add that providing data on these trends will help track trends in grid availability, including grid availability across utilities, as between load and distributed generation, and over time. COSSA/SEIA further argue this information will increase accountability and transparency and is not duplicative of information that is already available.

31. COSSA/SEIA respond to Public Service's concerns on the definition of "Hosting Capacity Analysis," arguing the Commission should tailor the rules to be flexible enough to permit the inclusion of any new modeling tools or technologies that may arise in future years. Therefore, rather than categorically limiting the definition of hosting capacity to include only non-exporting battery storage, COSSA/SEIA recommend the Commission adopt an approach that allows for inclusion of such information if or when it becomes available.

32. AEEI agrees with COSSA/SEIA, stating that while modeling exporting battery storage may introduce additional complexity to HCA, the Commission should not codify limiting qualifiers in its Rules. In response to SB 21-261 and its requirement that qualified utilities develop optional tariffs and programs for distributed storage, AEEI anticipates that battery storage deployment will only continue to grow in the near-term – making it more important to understand how storage is interacting with the grid.

c. Findings and Conclusions

33. We continue to agree with participants, including WRA/CEO and AEEI, who have supported the separate definition of demand flexibility and the important role it can play in a modernized grid beyond the traditional role of demand response. We acknowledge that the utilities still see additional need for differentiating the definitions between the two concepts.

34. We agree with WRA/CEO that Public Service's proposed amendments significantly and unnecessarily narrow the concept of demand flexibility to only reducing peak demand. As set forth in the Recommended Decision, demand flexibility is far broader than solely peak load reduction—it can also serve other purposes such as the shifting of load to avoid renewable curtailment or minimize GHG emissions. Demand flexibility should broadly and inclusively apply to different supply and demand techniques and technologies that, when coupled with communications technologies, can help the utility manage and balance the load on its system. Therefore, we modify and adopt the additional language provided by WRA/CEO that explains that demand flexibility can achieve more than just peak load reduction.

35. We further agree with COSSA/SEIA that the requirements in the proposed rules regarding grid availability are an opportunity for the Commission and stakeholders to view trends in grid availability, including grid availability across utilities, as between load and distributed generation, and over time. As COSSA/SEIA explain, this information will increase accountability and transparency and is not duplicative of information that is already available.

36. We also agree with Public Service in part, that HCA software is currently unable to model the complexities of exporting storage. However, we agree with COSSA/SEIA and

AEEI that the rules should be flexible enough to permit the inclusion of any new modeling tools or technologies that may arise in future years. Therefore, we adopt COSSA/SEIA's additional clarifying language to provide flexibility for future software capabilities.

3. Rule 3529 – Contents of the DSP

37. The Recommended Decision's adopted Rule 3529 meets the directive of SB 19-236, which directs the Commission to determine what must be included in a DSP filing, which at a minimum must include system and substation historical data, peak demand, forecasts of DER adoption, and current distribution investments. Proposed Rule 3529 lists the required contents of each plan.

a. Exceptions

38. WRA/CEO state that the Recommended Decision does not adopt the Joint Stakeholders' recommendation to require utilities to include any proposed request for proposal (RFP) documents and model contracts that the utility intends to use for NWA solicitation or procurement. WRA/CEO state they continue to believe it is prudent for the Commission to be provided an opportunity to review these documents and contracts, because the contents of the RFP documents will affect the level of third-party interest, and ultimately, the success of the NWA solicitation. They recommend inserting additional text as a new Rule 3529(X) within recommended Rule 3529.

39. COSSA/SEIA also recommend that the Commission require the utilities to provide with their Phase I distribution system plans, copies of model solicitation materials and any relevant model contracts. COSSA/SEIA note that the Commission currently requires the utilities to provide these materials in both Electric Resource Planning (ERP) and Renewable

Energy Standard (RES) proceedings. COSSA/SEIA provide rule language that includes not just NWA solicitation and procurement, but also other pilots and programs.

b. Responses

40. Public Service agrees with the exceptions filed by WRA/CEO and COSSA/SEIA, stating that given the parallels to the ERP process, it is appropriate and helpful to provide RFP documents and RFP model contracts that will be used to solicit NWAs as part of the Phase I DSP filing. Public Service states that given the uniqueness and diversity of potential DSP pilots and programs, they believe this additional rule language should be limited to NWA RFP documents and RFP model contracts, and request that the Commission adopt WRA/CEO's narrower proposed language rather than COSSA/SEIA's more expansive rule language.

c. Findings and Conclusions

41. We agree with WRA/CEO and adopt the proposed language changes. As Public Service points out, the NWA solicitation process is modeled after the Commission's ERP process. Therefore, we believe that it is appropriate and helpful to provide RFP documents and RFP model contracts that will be used to solicit NWAs as part of the Phase I DSP filing. We agree with Public Service that COSSA/SEIA's additional language would require utilities to provide proposed documents and model contracts for "other pilots and programs," which would be outside the scope of the NWA solicitation process.

4. <u>Rule 3530(a) – Distribution System Forecasts</u>

42. SB 19-236 requires the utility to provide "a forecast of the growth of distributed energy resources for the years covered by the plan." The Commission proposed an approach in Rule 3530 using Multiple Load, DER Growth, and NWA scenarios to assess current system capabilities, identify incremental infrastructure requirements, and enable analysis of the

locational value of DERs and NWA. All the forecasts would project load ten years into the future, with data to be provided for each year over the ten-year span.

a. Exceptions

43. Public Service requests that the word "energy" be deleted from this section because: 1) the Company does not forecast energy needs on a locational specific level (but does so at the system level, *e.g.*, in the ERP context); and 2) the Company only identifies distribution planning needs for capacity based upon peak loading conditions measured in MVA or MW.

44. Black Hills also argues that it is not appropriate to include an "energy" forecast within the planning period. From the DSP perspective, Black Hills states the type or amount of energy has no relevance, as the DSP is designed and managed based on demand, not energy.

b. Findings and Conclusions

45. We grant Public Service and Black Hills' request to delete the term "energy" in Rule 3530. We agree with the utilities, who point out that excluding the term 'energy' in this context is consistent with the further defined requirements relating to the reporting of "peak load growth" defined in subparts Rule 3530 (a)(I) through (a)(V).

5. <u>Rule 3530(a)(X)(A) – Forecast Scenarios</u>

46. The Recommended Decision adopted a two-scenario process for forecasting DER and NWA growth, including a business-as-usual case based on current State policy, as well as a High Growth scenario. The Recommended Decision agreed with CEO, which proposed a "State Policy Goal Scenario" that assumes alignment with State policy goals such as GHG reduction targets, Electric Vehicle deployment levels, Demand-Side Management, and RES

targets needed to achieve the State’s policy goals. One example of a State policy scenario is Governor Polis’ GHG Reduction Roadmap (Roadmap) which provides an assumed pathway for achieving Colorado’s science-based climate goals, established by House Bill 19-1261. However, State policy goals may evolve over time and each DSP application, along with its scenarios, should take into account the State policy goals in place at the time of the application.

a. Exceptions

47. Public Service suggests amending Rule 3530 (a)(X)(A) from “State Policy Goal Scenario” to “State Policy Mandate Scenario.” The Company believes the intent of this scenario is to reflect growth in load and DERs that may be more accelerated than business-as-usual or mandated requirements in order to remain compliant with State policy mandates. Public Service argues that the proposed change may eliminate future confusion around the broad term “goals” which, for instance, could be competing goals from different agencies or branches of State government.

48. Public Service also suggests the elimination of the phrasing “each line segment.” The Company states it is unaware of any tools available today which allow for forecasting at the line segment level. Public Service adds that forecasting DER adoption on a system-wide basis provides false precision, and the resultant value would not correspond to the extensive labor hours it would require to develop and implement a process to achieve these results.

49. Public Service also notes in paragraph (X) of Rule 3530(a) that it does not have the capability to track exported generation for all DERs. For example, the Commission’s decision to no longer allow the Company to require production meters for solar photovoltaic (PV) systems 10 kW or less means that the Company can only estimate gross production and

export of these systems, and accordingly, it states that the distribution system only physically sees the impact of the net load (*i.e.*, gross consumption – gross generation). The Company suggests modifying this paragraph.

b. Responses

50. WRA/CEO state they strongly disagree with Public Service's proposed changes. They state that while they understand that Public Service intends to avoid potential confusion around the broad term "goals," limiting this analysis to only "mandates" would result in a vastly incomplete assessment of the potential changes to the distribution system. WRA/CEO argue that while some statutory requirements dictate quantitative outcomes for energy usage or the grid (*e.g.,* energy efficiency resource standards), other statutory requirements instruct actions which are not themselves directly associated with tangible effects on the distribution system.

51. COSSA/SEIA argue that Public Service seeks to change the parameters of distribution system forecasting substantially by shifting from forecasting State policy goals, as part of its baseline forecasting scenario, to forecasting only State policy mandates. COSSA/SEIA believe the Commission should require the utilities to include in baseline, distribution system planning forecasting scenarios policy goals, including those outlined by the Governor, by the Colorado Legislature, or by administrative agencies acting under delegated authorities. COSSA/SEIA believe that not only should the utilities incorporate such goals into baseline forecasting scenarios, they should also incorporate their own utility corporate goals, adding that if the utilities' own goals and the goals of the State are not incorporated into baseline planning and forecasting, then these goals will not be achieved.

52. COSSA/SEIA also respond to Public Service's request to strike the requirement to forecast DER and NWA deployment at the feeder level "down to each line section," as specified in recommended Rule 3520(a)(X)(A). COSSA/SEIA note that Public Service provides this level of information in its Minnesota territory (as shown in Attachment A to COSSA/SEIA's response to exceptions), therefore, the Commission should require Public Service to provide equal access to information in Colorado.

c. Findings and Conclusions

53. We deny Public Service's request to modify the proposed rules from "goal" to "mandate." We agree with the Recommended Decision, which clearly pointed to the need to align the DSP planning process with existing State policy goals. As the Decision points out:

> The Commission plays an important role in achievement of the State's statutory climate goals and achievement of these goals is a necessary base assumption for any scenarios that are evaluated. The State's policy goals should be treated as the floor, not the ceiling, for planning of the State's utility infrastructure.[4]

54. In addition, WRA/CEO point out that limiting this analysis to only "mandates" would result in an incomplete assessment of the potential changes to the distribution system. We note that while some statutory requirements dictate quantitative outcomes for energy usage or the grid (*e.g.,* energy efficiency resource standards), other statutory requirements instruct actions, which are not themselves directly associated with tangible effects on the distribution system, such as transportation and building electrification.

55. We deny Public Service's request to delete "down to each line section." COSSA/SEIA point out in its response that detailed feeder data are provided in Xcel Energy's

[4] Decision No. C20-0837 at ¶ 63

HCA maps in Minnesota. Given the Commission's goals of greater transparency, this information is useful for certain stakeholders, including the Commission.

56. We grant Public Service's additions to Rule 3530(a)(X). We agree with Public Service's modification that provides flexibility regarding the Company's ability to estimate gross production and export of these systems due to the current option of production meters for solar PV systems of 10 kW or less.

6. Rule 3531(a)(II)(B) and (D) – Forecasting Hosting Capacity

57. Rule 3531(a)(II) specifies that the utility shall also provide a detailed narrative describing the utility's progress towards providing publicly available, real-time hosting capacity data. This should include discussion on how its HCA currently advances customer-sited DERs (in particular, solar PV and battery storage systems), how the utility anticipates the HCA identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which the utility anticipates customer benefit stemming from HCA.

a. Exceptions

58. Public Service takes exception to the requirements under proposed Rules 3531(a)(II)(B) and 3531(a)(II)(D) and suggests eliminating the requirement to forecast hosting capacity. The Company argues that hosting capacity serves as a snapshot in time and is therefore highly dependent upon current grid conditions including electrical connectivity, penetration and location of existing DER, the number of projects and lack of certainty of projects in the interconnection queue, and other factors. Public Service further argues that forecasting future State hosting capacity is at best a speculative practice, which would require

the Company to make numerous, layered assumptions on factors which it does not directly control or influence.

59. Public Service notes that it has no way of forecasting unplanned outages or contingencies, therefore, the Company proposes the elimination of Rule 3531(a)(II)(D).

60. WRA/CEO believe that Rule 3531(a)(II)(D) would benefit from additional clarity. The recommended rule instructs utilities to "evaluate hosting capacity need under normal and planned and unplanned contingency conditions, as well as under the High Growth scenario." In this phrase, WRA/CEO believe the meaning of "normal" is unclear. WRA/CEO state they presume the Recommended Decision intended to use the word "normal" to refer to the State policy scenario, since it indicates that the Roadmap—which corresponds with this scenario—should be assumed as the "business-as-usual" scenario. If this assumption is correct, then WRA/CEO believe this rule could be clarified by specifically referencing the State policy scenario.

b. Responses

61. COSSA/SEIA acknowledge Public Service's concern and as an alternative minimum to this requirement, the Commission should at least require the Colorado utilities to provide the same information that Public Service provides in Minnesota, which includes a link to the public queue for distributed generation as a data point included in the HCA map. Providing this information would put Colorado on more even footing with Public Service's other service territories and would improve access to information related to future changes in hosting capacity at a given location.

62. In response to WRA/CEO's exception, Public Service disagrees with WRA/CEO's interpretation and all alternative interpretations presented by WRA/CEO. The

Company argues that nothing in the Recommended Decision discussing hosting capacity suggests that the utility shall be required to provide forward-looking analysis or estimates of future hosting capacity. Public Service further argues that given that the scenario analyses required for both the State Policy Goal and High Growth Scenarios forecasts are forward-looking, the Company maintains it is not appropriate or consistent with industry practices to forecast hosting capacity, regardless of the scenario. Therefore, they believe presumed interpretation of Rule 3531(a)(II)(D) by WRA/CEO should be disregarded.

c. Findings and Conclusions

63. We deny Public Service's request to only analyze existing conditions in its HCA exceptions. We believe that dynamic hosting capacity analysis will evolve over time. We acknowledge that with current software, snapshot (or static) hosting capacity is common. We note that the Recommended Decision directs the HCA process to evolve over time through the stakeholder process and as software advances are made. We recognize COSSA/SEIA's response to Public Service and note that at a bare minimum for the first DSP application, a utility such as Public Service may provide the same information it currently provides in Minnesota.

64. We grant WRA/CEO's request for additional clarity as its proposed language captures the goals of the Recommended Decision. The term "normal" refers to conditions operating under the State policy scenario, or "business-as-usual." This clarification is helpful, and despite the utilities' statements that only snapshots of hosting capacity are available using current software, we are confident that the rules provide the flexibility needed as the HCA process evolves over time into a dynamic analysis that will consider the behavior of DERs, loads, and grid devices.

7. Rule 3531(a)(II)(G) – HCA Requirements

65. The Recommended Decision recognized that smaller utilities such as Black Hills should develop their HCAs in a phased approach, as Black Hills currently does not have the software capability to provide hosting capacity maps. The Decision emphasized that working towards deployment of robust HCA and, in turn, better coordination on the distribution system, should yield long-term savings, rather than net costs, for all utilities.

a. Exceptions

66. WRA/CEO state that they support Rule 3531(a)(II)(G), which allows more leniency for a small utility in its first DSP. In exceptions, they recommend one addition, however, to help the Commission and stakeholders better understand the current data capabilities of such utilities.

b. Findings and Conclusions

67. We grant the additional language provided by WRA/CEO to increase the transparency of the DSP application. We agree that it is important for utilities to be open and transparent with the Commission regarding their plans to improve data collection and analysis capabilities as the utility adapts to a future where more data needs to be evaluated in the DSP process.

8. Rule 3532(d)(I)(F) - Interconnecting Community Solar Garden

68. The Recommended Decision added language in 3532(d)(I)(F) that will allow the Commission to determine whether the Action Plan requires specific investments that will enable cost-effective and efficient interconnection of expected Community Solar Garden (CSG) capacity. The Decision expanded upon this concept to include DER capacity, which

may include other DER project types, which are also important in pursuit of Colorado's policy goals.

a. Exceptions

69. Public Service argues it already provides this type of assessment through HCA on a system-wide basis, modeled on current system configuration. The Company adds that moving towards more frequent hosting capacity updates as required by Rule 3541(d)(II)(F) will partially address this requirement. Public Service states it could provide or publish additional indicators at the system-level, such as the name and location of substations already equipped with voltage-supervision-of-reclosing (VSR) and 3V0 protection for ground faults, as these are common and typically costly upgrades that can be triggered by solar PV. Therefore, Public Service argues substations already equipped with these upgrades are likely to be more suitable for solar development.

b. Responses

70. In its response, SunShare points out that the purpose of Rule 3532(d)(I)(F) was to afford the opportunity for the Commission to potentially increase available CSG interconnection capacity on the distribution system. This would be accomplished through expanded or new substations, protective equipment to avoid issues to load serving stations, and facilitate visibility into the hosting capacity of the system where that capacity reaches areas conducive to solar development.

71. SunShare argues that Public Service's proposed revisions to the Grid Needs Assessment (GNA) would make that provision redundant with the HCA. Hosting capacity is defined in the DSP Rules in terms of capacity that a given feeder can interconnect without requiring upgrades. SunShare points out that Public Service proposes to change the GNA to

"provide information on substations . . . that may be more suitable"[5] for future interconnection. This would be substantially the same as the separate requirement in the DSP Rules for the Company to provide the suitability of substations to accommodate capacity today.

72. SunShare believes that Public Service argues, on the one hand, that a GNA cannot provide more than an HCA without specific locations of CSGs, and then on the other hand, argues an HCA cannot be applied beyond the present. Between its proposed revisions to the Hosting Capacity and GNA rules, SunShare argues "the Company would have no obligation to address the capability of its system to expand to interconnect reasonably anticipated future CSG capacity."[6] However, for clarification purposes, SunShare proposes a modification to add to Rule 3532(d)(I)(F) based on Public Service's proposed language.

73. COSSA/SEIA recommend the Commission require the utilities to provide not just information about VSR and 3VO capabilities, but all major capabilities that Public Service provides in its electric service territory in Minnesota. COSSA/SEIA state that they understand that in Minnesota, Public Service provides a variety of helpful details such as substation daytime minimum load, substation absolute minimum load, feeder daytime minimum load, and feeder absolute minimum load. The Colorado utilities should provide a level of detail in this jurisdiction that is at least equal to the level of detail that Public Service is already providing in its Minnesota territory.

[5] SunShare's Response at p. 6.
[6] ***Id.***

c. Findings and Conclusions

74. We grant in part and deny in part Public Services' exceptions. We do not agree with Public Service's modifications to this rule but clarify some of the issues that Public Service presents.

75. We believe that in its response to the exceptions, SunShare accurately represents the goals of this particular rule. SunShare correctly points out that Public Service's proposed language would hobble the obligation to assess its grid's future needs by instead focusing on its then-present interconnection queue, which would frustrate the purpose of the DSP Rules to be a planning exercise. The Commission is aware of issues surrounding the interconnection of CSGs, as recently updated CSG and Interconnection Rules and current interconnection investigations make clear.

76. To help clarify potential confusion represented by Public Service's position, we agree that additional language would be helpful and that SunShare's addition captures some of Public Service's request for clarity in a more readable way. Again, we agree with COSSA/SEIA that with the goals of transparency in mind for the DSP process, the level of detail provided in Minnesota should be the minimum of what is provided in Colorado.

9. NWA Suitability Exemptions (Rules 3532(d)(II)(A), 3534(b)(IV), and 3534(c)

77. Proposed Rule 3532 requires a Grid Needs Assessment to identify the need for critical capacity additions or NWAs that will be needed for substation transformers and feeders that are forecasted to have insufficient capacity to adequately serve peak load over the ten-year horizon.

78. Public Service proposed a new exception to help utilities maintain the flexibility to address planning needs as they are identified (whether through traditional solutions or NWA) to serve customers in a timely and cost-effective manner. Public Service explains that under its current planning process, it maintains flexibility to address planning needs with solutions and mitigations as early as January of the current planning cycle (approximately three months after the planning cycle begins in September). The Recommended Decision agreed with Public Service and added the modified language regarding exemptions for short-term planning needs in Rule 3532(d)(II).

79. The Decision added additional language specifying that as part of its assessment, the utility must adequately explain why this grid need was not previously identified. The Decision stated that it is the Commission’s goal that utilities have an ability to expeditiously meet needs when necessary, but to balance that with the concept that the regular course should be for grid needs to be identified earlier and to follow the outlined process.

80. Proposed Rule 3534 on NWA Suitability Screening Rule stems from SB 19-236, which instructs the Commission to develop a methodology for evaluating the costs and net benefits of using DER as an NWA and to determine a threshold for the size of a new distribution project for when a utility must consider implementation of an NWA. The Recommended Decision adopted language from both the Joint Stakeholders and Public Service. The Decision also attempted to balance the needs of the utility with a robust, transparent process for DSP. The Decision stated that the NWA suitability screening process is intended to be the typical pathway for investments meeting the criteria and justification would be required to identify why that process cannot or should not be followed in specific instances.

a. Exceptions

81. While they admit that there are circumstances where NWAs are not a viable solution to a particular grid need, WRA/CEO argue that the proposed rules give the utilities an excessive amount of leniency in opting out of the NWA assessment process even where an NWA may be viable, and do not consistently require utilities to explain decisions or provide the rationale for pursuing conventional projects without evaluating available alternatives.

82. WRA/CEO further argue that utilities should not be allowed a blanket opt-out for near-term projects unless there is a legitimate issue with viability. They believe that while project urgency can certainly limit project viability in some cases, it will not exclude NWAs as a solution in all cases. WRA/CEO state utilities should be required to assert and explain any claimed exemption, instead of simply noting the reason that they did not identify the grid constraint earlier.

83. WRA/CEO propose eliminating recommended Rules 3532(d)(II)(A) and 3534(b)(IV) and expanding recommended Rule 3534(c) to incorporate aspects of recommended Rules 3532(d)(II)(A) and 3534(b)(IV). WRA/CEO believes this approach offers a more robust, flexible, and centralized approach to NWA analysis exemptions, without unnecessary rigidity in the types of projects that may receive exemption.

84. WRA/CEO also argue that while there will likely be cases where it proves impractical to pursue NWAs for these types of grid needs, there may also be opportunities where DERs are particularly suitable. For example, in the context of wildfire mitigation, there could potentially be opportunities for remote grid or microgrid solutions, like utilities in other regions are pursuing. Moreover, WRA/CEO believe that this rule is redundant with other recommended rules.

85. WRA/CEO suggest that the clarity of the recommended rules could be improved by consolidating all provisions related to exemptions or waivers from the NWA suitability evaluation within a single, comprehensive rule. Currently, rules regarding exemptions and waivers are found in recommended Rules 3532(d)(II)(A), 3534(b)(IV), and 3534(c), and each rule has a different requirement for substantiation for different types of exemptions and suggest the language changes for Rule 3534(c).

b. Responses

86. Public Service argues that the short-term planning exemption in Rule 3532(d)(II)(A) reflects the fact that Major Distribution Grid Projects require significant lead-time to develop and implement planning solutions, both for traditional wire solutions and NWAs, compared to smaller grid needs. The Company states that this time accounts for steps in the process including analysis of solutions, material procurement, construction, and commissioning. The Company believes its recommended language, which was largely adopted in the Recommended Decision, is consistent with NWA regulatory practice in other states for large distribution planning needs. The Company also disagrees with WRA/CEO's interpretation that this Rule allows utilities "to opt out of assessing an NWA for any grid constraint occurring in the subsequent three years."[7]

87. Public Service responds that Rule 3534(b)(IV) reflects project types that typically have immediate impacts on system reliability and resiliency and often require immediate investments by the Company to preserve reliability. Therefore, the Company argues Rule 3534(b)(IV) should be maintained as currently written.

[7] WRA/CEO Exceptions at p. 9.

88. Finally, Public Service states that Rule 3534(c) allows a utility to invoke the more formal Commission waiver process under PUC Rule 1003 of the Rules of Practice and Procedure, 4 CCR 723-1, on a case-by-case basis for unforeseen circumstances not covered by the previous two rules pertaining to exemptions. To eliminate some of the redundancy which WRA/CEO asserts is present amongst these three rules, the Company suggests Rule 3534(c) could be clarified slightly.

89. AEEI states that they agree with WRA/CEO that this provision is overly broad and provides utilities with undue discretion to dismiss potential NWA solutions for grid constraints anticipated within a 36-month timeframe. AEEI believes there has been little evidence presented through the course of this proceeding that suggests that NWAs are categorically infeasible to implement within a three-year period.

c. Findings and Conclusions

90. We grant WRA/CEO’s exception and eliminate recommended Rules 3532(d)(II)(A) and 3534(b)(IV), and expand recommended Rule 3534(c) to incorporate aspects of recommended Rules 3532(d)(II)(A) and 3534(b)(IV).

91. We recognize that the Recommended Decision specifically addressed the concerns by stating that as part of its assessment, the utility must adequately explain why this grid need was not previously identified. We agree with WRA/CEO that such a requirement may not go far enough to maintain transparency from the utilities. We believe WRA/CEO provide a substantial clarification by recommending the consolidation of all provisions related to exemptions or waivers from the NWA suitability evaluation within a single, comprehensive rule.

92. Using WRA/CEO's updated rule language, a consolidated rule would be most appropriate as Rule 3534(c). Rule 3532 should focus on grid needs—not specific solutions—and Rule 3532(b) should solely list the NWA suitability screening criteria. We agree with WRA/CEO that this approach offers a more robust, flexible, and centralized approach to NWA analysis exemptions, without unnecessary rigidity in the types of projects that may receive exemption. We do not believe these changes impact the utilities' ability to request exceptions for Major Distribution Grid Projects. These changes merely consolidate rule language for improved clarification, and also increase the transparency from utilities who request exemptions.

10. Rule 3535(a) – NWA Cost Benefit Analysis

93. This rule directs the utilities to provide an assessment of the proposed NWA solution using the cost-benefit analysis (CBA) methodology put forward in the most recent version of the National Standard Practice Manual (NSPM) and specifically includes certain costs and benefits. The Recommended Decision added language to provide flexibility that will allow the utilities and stakeholders to develop robust CBA methodologies over time.

a. Exceptions

94. WRA/CEO state that Rule 3535(a) could be read as a relatively broad requirement that would be better located in Rule 3529, which governs the contents of the distribution plan. WRA/CEO believe it could also be read as applying only to singular NWA solutions. They argue that if this rule is meant to apply broadly to the entire DSP, WRA/CEO believe moving this language to Rule 3529 is a better solution.

95. WRA/CEO state they are also unclear on whether proposed Rule 3535(a)(IV) applies to an individual NWA analysis or the broader set of DSP investments. The intention of

the rule could be clearer if it were not nested under subparagraph (a)—which pertains to the assessment of individual NWAs—but rather relocated to Rule 3535(b).

96. Finally, given that recommended Rule 3535(a) requires a utility to propose a methodology in its DSP, WRA/CEO find the retention of recommended Rule 3535(b) redundant. WRA/CEO note that under recommended Rule 3535(a)(I), utilities are already permitted to propose a methodology that accounts for costs and benefits beyond those listed in recommended Rule 3535(a)(II), as long as utilities "consider" the approach in the NSPM—the rule does not explicitly require utilities to adopt any particular aspect of the NSPM into their proposed methodology. WRA/CEO recommend eliminating recommended Rule 3535(b).

b. Responses

97. Public Service disagrees with WRA/CEO's recommendation to eliminate subsection (b) of Rule 3535. While the Company intends to work with stakeholders to develop and publish a CBA methodology consistent with Rule 3535(a) that would be used to assess most, if not all NWA bids for Major Distribution Grid Projects, there may be circumstances where it may be more practical for the utility to propose an alternative or adjusted methodology.

c. Findings and Conclusions

98. We deny WRA/CEO's exceptions. The Proposed Rules interpreted SB 19-236 as developing a CBA for individual NWA projects. We note that the Recommended Decision declined to adopt OCA's suggestion to develop a rule to require a comprehensive DSP CBA that looks at individual investments and system investments as a whole to create a full picture of how these plans will support decarbonization.

99. As Public Service points out, as directed by SB 19-236, the Recommended Decision directs the utilities to work with stakeholders to develop and publish a CBA methodology consistent with Rule 3535(a) that would be used to assess most, if not all NWA bids for Major Distribution Grid Projects. Rule 3535(b) simply allows more flexibility for the Commission to evaluate alternative or adjusted cost-benefit methodologies.

11. Rule 3536 – Action Plan

100. Proposed Rule 3536 requires the utility to provide a five-year Action Plan for distribution system investments and activities, including the plans for soliciting the deployment of DERs, as well as plans for permitting, constructing, preparing required reports, and other significant activities where replacement, upgrades, or expansion of utility infrastructure has been identified as the best option.

a. Exceptions

101. In its exceptions, WRA/CEO point out that Recommended Rule 3536(b) lists the information that utilities must provide in the Phase I Action Plan, "for each action *that will not require a solicitation process* following Phase I." WRA/CEO state that the first item on this list is "the implementation of NWAs identified through the NWA cost benefit analysis process."[8] They believe that inclusion of this item in the Phase I Action Plan introduces confusion about the timeline for NWA solicitation for major distribution grid projects. WRA/CEO recommend Rule 3536(b)(I) be amended.

102. Black Hills points out that Rule 3536(a) provides that the Phase I action plan "will serve as an application report for the Commission . . . ."[9] Based on Rule 3529(a)(X), Black

[8] *Id.* at p. 14,

[9] Black Hills' Exceptions at p. 5.

Hills believes it was the Commission's intent that the action plan serves as a report within the DSP application. Black Hills seeks clarification that the action plan is a report that it is not filed as a separate application with a separate litigation from the Phase I DSP application.

b. Responses

103. Public Service supports the language proposed by WRA/CEO, which clarifies Rule 3536(b)(I) should be limited to grid needs not classified as Major Distribution Grid Projects.

104. WRA/CEO agree with Black Hills, stating Rule 3536(a) is the only place the proposed rules use the term "application report." Rule 3528, which details Distribution System Plan Filing Requirements, does not use the term "application report." Nor does Rule 3539, which details the contents of a plan. Therefore, to provide the clarity that Black Hills requests, the Joint Respondents suggest striking the word "report" from Rule 3536(a).

c. Findings and Conclusions

105. We grant WRA/CEO's proposed language to Rule 3536(b)(I) and we grant Black Hills' exception and remove the term "report" in Rule 3536(a). Both exceptions provide the rules with needed clarifications, as explained by the respective responses from Public Service and WRA/CEO.

12. <u>Rule 3537– NWA Solicitation Process</u>

106. During the Proceeding, Public Service proposed a new section to Rule 3537, which describes the Phase II NWA Solicitation process. Public Service expects to reflect NWA selections from the solicitation process in an updated Action Plan as per Proposed Rule 3537(e), and allow stakeholders to file comments on the final contracts in a non-litigated fashion. The Recommended Decision agrees with the Company that the Commission's current

ERP process should serve as a model for the DSP bid evaluation. The Recommended Decision agreed with Public Service, which points out that there are many parallels between the all-source ERP process and the technology-neutral solicitation process for NWAs pursuant to the proposed rules. Public Service notes that with regard to objective evaluation of NWA bids, the Commission rules for retaining an independent evaluator (IE) in the ERP process were created to ensure oversight and result in a fair process.

a. Exceptions

107. COSSA/SEIA argue that the Commission's rules should not eliminate all channels of communication between parties to the proceeding and the IE. Although the Commission did not adopt COSSA/SEIA's previous recommendation to establish an NWA Coordinator instead of an IE, they believe the Commission should at least allow the IE to receive tips and concerns from parties to the proceeding – so long as such parties are not also direct bidders – so that the IE can act on any relevant information as appropriate during the course of the solicitation process.

b. Responses

108. Public Service believes that COSSA/SEIA's recommendation modifying Rule 3537(b)(IV) is an inappropriate suggestion for several reasons but emphasizes two primary concerns. First, and most importantly, it undermines the independence of the IE role. Second, while organizations like trade organizations may not themselves be bidding in a solicitation process, many of their member organizations will likely be.

c. Findings and Conclusions

109. We deny COSSA/SEIA's request to modify rules regarding the IE process. We believe that as more experience with the NWA solicitation process is gained by all

stakeholders, including the Commission, steps can be taken when issues are identified. We believe that if potential issues with the solicitation process occur, the Commission can take subsequent steps directing Commission Staff to initiate contacts with the utility and potentially the IE regarding specific types of issues that may arise. We determine that codifying the ability of communication with the IE by parties is premature at this early stage.

13. Rule 3537(b)(II) – Bid Fees

a. Exceptions

110. Black Hills takes exception to the requirement in Rule 3537(b)(II) that the utility must pay for the services provided by the IE used for the NWA solicitation process. The Commission should revise this rule to clarify that a utility may collect reasonable bid fees to offset the cost of the IE.

b. Responses

111. WRA/CEO state they are not opposed to the collection of reasonable bid fees to offset the cost of the IE. However, WRA/CEO is concerned that unreasonable bid fees could create a barrier for effective solicitation of NWAs. WRA/CEO propose that to prevent this issue, and to ensure adequate transparency for NWA solicitation, the Commission require utilities to propose any desired bid fees in the Phase I filing for Commission review and approval. WRA/CEO offer a suggestion to modify recommended Rule 3537(b)(II), built off the language proposed by Black Hills.

c. Findings and Conclusions

112. We grant Black Hills' request in part with WRA/CEO's proposed language addition. We agree with WRA/CEO who point out that bid fees to offset the cost of the IE are justified; however, unreasonable bid fees could create a barrier for effective solicitation of

NWAs. WRA/CEO note that by using Black Hills' proposed language, the Commission would not have insight into the bid fees levied by utilities and therefore would be unable to determine if such fees were reasonable and productive for the procurement of NWA solutions

14. Rules 3538(b) and 3538(c): Approval and Funding from Other Proceedings

113. Recommended Rule 3538(b) allows utilities to seek approvals in other proceedings only pursuant to an approved DSP. The Recommended Decision adopted several modifications to what is now proposed Rule 3538 proposed by the Joint Stakeholders and Public Service. The Decision disagreed with the Joint Stakeholders that the Commission should not allow approvals for an NWA, pilot, or program in other existing proceedings. The Commission and stakeholders will continue to have to grapple with the increasing interrelationship between different proceeding types and the Decision states it is premature to preclude other options for approval and cost recovery at this time.

a. Exceptions

114. WRA/CEO interprets this Rule as a requirement for utilities to receive approval in a DSP before seeking a second approval in another proceeding, which WRA/CEO argues would be highly inefficient.

115. COSSA/SEIA recommend the Commission should make the limited clarification that any distribution system-related charges that may be recovered from the Renewable Energy Standard Adjustment (RESA) should reflect only the incremental costs of eligible energy resources and may not incorporate costs that the utility would otherwise expend for a traditional utility distribution system investment. Further, COSSA/SEIA believe the Commission should clarify that under no circumstances would a utility be permitted to charge the RESA for a level of costs that otherwise would be considered standard distribution system

investments recovered in a customer's base distribution rates. COSSA/SEIA state the Commission should make clear in its final decision that the use of RESA funds must be limited to any incremental additional costs incurred beyond simply the avoidance of traditional utility distribution upgrade costs.

b. Responses

116. Public Service agrees with WRA/CEO that the current language in Rule 3538(c), which requires the Commission to approve the utility's DSP prior to the utility seeking approval in other proceedings for DSP-related investments, could create inefficiencies. The Company supports WRA/CEO's proposed modification which strikes the phrase "pursuant to an approved DSP" from Rule 3538(b).

c. Findings and Conclusions

117. We grant WRA/CEO's proposed language deletion. As both WRA/CEO and Public Service point out, the phrase "pursuant to an approved DSP" could be inefficient as utilities may be required to receive approval in a DSP before seeking a second approval in another proceeding.

118. We deny COSSA/SEIA's request for clarification regarding RESA usage. We believe issues surrounding the RESA will be better explored and clarified in the forthcoming RES rulemaking.

15. <u>Rule 3541(b): Web Portal</u>

119. Proposed Rule 3541 directs the utility to develop a web portal with stakeholders that will help achieve the objectives of the DSP process. The web portal is intended to foster transparency, clarity, and convenience for stakeholders.

a. Exceptions

120. The Company suggests modifying the requirement that "[t]he utility may not deny access to its web portal" to "[t]he utility may only deny access to its web portal if visitors and/or registrants violate the terms of service or other agreed upon terms of access." Public Service believes that this proposed language adds necessary specificity and access control against malicious intent while still ensuring non-discriminatory access for legitimate purposes. The Company believes this change is a prudent one, and eliminates proscriptive language that is overly broad and could lead to unintended consequences.

b. Findings and Conclusions

121. We grant Public Service's exception. While the Commission will not necessarily know what specific terms of use or access will be associated with the website prior to a DSP application, we anticipate that these terms will be developed with stakeholders and may establish some standards associated with fair use and sharing of data. If the utility could not set a consequence for violation of reasonable terms of use, then any agreed-upon protections established with the website would lack meaning. We support Public Service's proposed language as clear, narrow, and reasonable.

16. <u>Rule 3542: Evaluation and Reporting</u>

122. Recommended Rule 3538(b) allows utilities to seek approvals in other proceedings only pursuant to an approved DSP. The Recommended Decision adopts several modifications to what is now proposed Rule 3538 proposed by the Joint Stakeholders and Public Service, and made several additional modifications. The Recommended Decision disagreed with the Joint Stakeholders that the Commission should not allow approvals for an NWA, pilot, or program in other existing proceedings. The Commission and stakeholders will

continue to have to grapple with the increasing interrelationship between different proceeding types and the Decision states it is premature to preclude other options for approval and cost recovery at this time.

a. Exceptions

123. WRA/CEO point out that the recommended rules do allow utilities to seek approval of DSP investments in other, non-DSP proceedings, and also to fund these projects using other, non-DSP sources of revenue. To avoid an unintended consequence of this increased flexibility, WRA/CEO suggest the Commission take additional steps to ensure the DSP functions as a centralized forum for reporting on distribution grid-related projects and increase transparency. WRA/CEO suggest the Commission add an additional rule requiring utilities to list DSP-funded projects proposed or approved in other proceedings and to describe the relevant funding sources.

b. Responses

124. Public Service agrees with WRA/CEO, stating it has supported a similar belief that each DSP could serve as an "executive summary" for DSP-related investments, including those which may be approved in other proceedings. While Public Service states it did not memorialize this concept in the proposed rules, the Company supports WRA/CEO's suggested addition of subpart (e) with minor modification.

c. Findings and Conclusions

125. We grant WRA/CEO's and Public Service's proposed language. The added language proposed by WRA/CEO captures one of the initial drivers of the DSP Rules, which was to ensure the DSP functions as a centralized forum for reporting on distribution grid-

related projects and increase transparency. Public Service's suggestion adds helpful language that will simplify the amount of information provided by limiting it to active projects.

17. Black Hills' Lookback Exception

126. Black Hills argues that because the DSP is filed every two years, there is no need for a three-year lookback. Such information will already be readily available to the Commission and any interested stakeholder in a previously submitted DSP. Black Hills requests this change throughout the Rules, including 3531(a)(I)(B), (G), and (R), 3532(d)(III), and 3539(a)(I) and (II)

127. We deny Black Hills' request for a two year, rather than a three-year lookback. Added transparency is a key goal of this DSP process, as explained in the Recommended Decision, therefore we feel it is important to see trends in the "three-year lookbacks" in various sections of the rules. Looking into previous DSP applications would be overly burdensome on many stakeholders, as compared with a potential minor inconvenience such requirements may cause the utilities.

18. Miscellaneous Edits and Clarifications

128. Several of the Participants' Exceptions suggested various grammatical changes and non-substantive edits to improve readability or accuracy of the DSP Rules. The Commission appreciates these suggestions, and the DSP Rules that we adopt today reflect those changes and edits.

II. ORDER

A. The Commission Orders That:

1. The exceptions to Recommended Decision No. R21-0387, filed by Public Service Company of Colorado on July 28, 2021, are granted in part, and denied in part, consistent with the discussion above.

2. The exceptions to Recommended Decision No. R21-0387, filed by Black Hills Colorado Electric, LLC on July 28, 2021, are granted in part, and denied in part, consistent with the discussion above.

3. The exceptions to Recommended Decision No. R21-0387, filed by Western Resource Advocates and the Colorado Energy Office on July 28, 2021, are granted in part, and denied in part, consistent with the discussion above.

4. The exceptions to Recommended Decision No. R21-0387, filed by the Colorado Solar and Storage Association and the Solar Energy Industries Association on July 28, 2021, are granted in part, and denied in part, consistent with the discussion above.

5. The Rules Implementing Distribution System Planning Procedures within the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* 723-3, contained in legislative (*i.e.*, strikeout/underline) format (Attachment A), and final format (Attachment B) are adopted, and are available through the Commission's Electronic Filings system at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=20R-0516E

6. Subject to a filing of an application for rehearing, reargument, or reconsideration, the opinion of the Attorney General of the State of Colorado shall be obtained regarding constitutionality and legality of the rules as finally adopted. A copy of the final, adopted rules

shall be filed with the Office of the Secretary of State. The rules shall be effective 20 days after publication in *The Colorado Register* by the Office of the Secretary of State.

7. The 20-day time period provided by § 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.

8. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING August 25, 2021.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

JOHN GAVAN

MEGAN M. GILMAN

Commissioners

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

3506. – 35~~19~~24. [Reserved].

DISTRIBUTION SYSTEM PLANNING

3525. Applicability

This rule shall apply to all electric utilities in the state of Colorado that own distribution facilities except municipally owned electric utilities and cooperative electric associations that have voted to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-104, C.R.S.

3526. Overview and Purpose.

The purpose of these rules, as directed by § 40-2-132, C.R.S., is to require electric utilities to file a Distribution System Plan (DSP) that enables the Commission to review and evaluate the utility's investments in the distribution grid to ensure that they cost-effectively support grid adequacy, reliability and resilience and prepare for new expectations upon the distribution system, while simultaneously ensuring progress toward priorities highlighted by state legislation, including but not limited to supporting diversification of energy supply through distributed energy resources, expanding the utilization of non-wire alternatives that may reduce the need for conventional distribution grid investment, reducing greenhouse gas emissions, advancing building and transportation electrification, maintaining affordable customer rates, and promoting equity with regard to disproportionately impacted communities. These rules should also establish a proactive and transparent process for enhancing understanding of key distribution system characteristics.

3527. Definitions.

The following definitions apply to rules 3525 through 3542. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Ancillary services" means the functions that maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event. Ancillary services include but are not limited to synchronized regulation, contingency reserves, flexibility reserves, voltage and frequency response, power factor corrections, and spinning reserves.

(b) “Capacity need” means a distribution grid capacity constraint or shortfall projected within a ten-year period.

(c) “Demand flexibility” means the ability to help utilities manage or balance load by shifting electricity use across hours of the day to reshape customer load profiles or dynamically respond to system conditions while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality and delivering net benefits to the system, customers, or society. Demand flexibility often uses distributed energy resources, communication and/or control technologies.

(d) “Demand response measures” or “demand response” or “DR” means any modulation in customer electric usage at targeted times, including reduction of usage or shifting of usage from one time to another, or interruption or curtailment of electric usage, either with load control equipment or in response to incentives, a signal, or changes in the price of electricity designed to induce changes in electricity use at specific times.

(e) “Direct current fast charger” means a high-power fast charging method of at least 50 kW capacity used to resupply an electric vehicle using direct current electricity, typically 208/480V three-phase.

(f) “Distributed energy resources” or “DER” may include, but are not limited to, distributed generation, energy storage systems, electric vehicles, microgrids, fuel cells, and demand side management measures including energy efficiency, demand response, and demand flexibility that are deployed at the distribution grid level, on either the customer or utility side of the meter. DER can be used to optimize energy use and generation to satisfy the energy, capacity, or ancillary service needs of the distribution grid.

(g) “Distribution system plan” or “DSP” means the compliance plan filed in accordance with rule 3528.

(h) “Energy efficiency measures” are measures that target consumer behavior, equipment, or devices that result in the decrease in electricity usage of customers without detriment to end-use services.

(i) “Grid availability” means the hours per year when the utility makes the grid or a portion of the grid available for use not only by load but also by distributed generation and demand response.

(j) “Grid need” means the need for energy, capacity, ancillary services, reliability, or resiliency services to address a forecasted deficiency on the electric distribution system.

(k) “Hosting capacity” means 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.

(l) “Locational value” means an analysis of distributed energy resources that incorporates location-specific incremental net benefits to the electric grid.

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

(n) “Microgrid” means a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that can act as a single controllable entity with respect to the grid. A microgrid is capable of connecting and disconnecting from the centralized grid to enable the microgrid to operate in both grid-connected or island-mode.

(o) “N-1 event” means an outage event of one distribution or transmission element such as a transformer, feeder, or transmission line that may cause load to shift to other elements as backup. An N-1 event indicates a need for additional reliability capacity if it is determined to cause a potential overload on elements carrying energy to accommodate the event.

(p) “Non-Wires Alternative” or “NWA” means the strategic deployment of distributed energy resources by a utility or a third party and associated control or aggregation of systems and technologies intended to cost-effectively defer or avoid the need for Major Distribution Grid Projects. An NWA is intended to reliably reduce load, congestion or other constraints at times of peak demand in targeted locations on the grid. NWAs can include one or multiple DER, including but not limited to demand response measures, energy efficiency, energy storage, and distributed generation. NWA projects can include these and other investments individually or in combination to meet the specified need.

(q) “Pilot” means a utility offering to test a new use or deployment of DER for a set period of time with a specified end date and number of customers, wherein the utility seeks to gain experience or expertise, and to inform the Commission.

(r) “Program” means an ongoing, long-term offering by the utility with no specified end date that utilizes or deploys DER on the distribution grid in a manner that provides system benefits or cost savings.

(s) “Ratable procurement” means the procurement of incremental DER capacity to defer or avoid long-term traditional utility infrastructure or grid needs driven by steady load growth.

(t) “Reliability need” means a risk of failure requiring mitigation due to inadequate capacity or voltage support, or an N-1 event on the distribution grid.

(u) “Resilience” is the ability of the distribution grid to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.

3528. Distribution System Plan Filing Requirements.

A utility with over 500,000 customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2022. A utility with 500,000 or fewer customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2023.

(a) Each DSP application filing shall conform to the application requirements contained in rules 3002 and rule 1303 of the Commission's Rules of Practice and Procedure.

(b) Within 30 days of the filing of the application, the Commission shall issue a decision addressing whether the contents of the DSP meet Commission standards based on the information provided by the utility set forth in paragraph 3528(d).

(c) If the DSP identifies major distribution grid projects that meet the NWA suitability screening criteria put forth in paragraph 3534(a), then the DSP proceeding shall consist of two phases.

(I) Within the same proceeding and subject to paragraph 3528(b), the utility shall file a Phase II DSP within 120 days of the filing of the Commission's order establishing the final Phase I DSP.

(A) Within 30 days after the filing of the Phase II DSP, parties may submit comments pertaining to the Phase II DSP.

(B) Within 15 days after the deadline for initial comments on the Phase II DSP, parties may submit reply comments.

(d) If the utility claims that any of the requirements set forth in rules 3529 through 3541 are not yet practicable to provide or are currently cost-prohibitive to provide, the utility shall indicate for each requirement:

(I) why the information is not yet practicable or is currently cost-prohibitive, what information could be provided in the alternative and how that alternative information would achieve planning and policy objectives.

(II) how the information could be obtained in future filings, and if so, at what estimated cost, and on what timeframe;

(III) what the benefits or limitations of filing the data in future reports would be as related to achieving the planning and policy objectives; and

(IV) if the information cannot be provided in future reports, what information could be provided in the alternative and how it would achieve planning and policy objectives.

(e) The utility shall file a final DSP action plan in accordance with rule 3536, including all required modifications, within 60 days of the Commission's final decision.

(f) The utility may file, at any time, an application to amend the contents of a DSP approved pursuant to paragraph 3536(c). Such an application shall meet the requirements of paragraphs 3002(b) and 3002(c), shall identify each proposed amendment, shall state the reason for each proposed amendment, and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

(g) Utilities are encouraged to convene regular, informal stakeholder meetings to discuss DSP-related issues and to inform the contents of DSP applications. The utility shall convene at least one stakeholder meeting at least 90 days prior to the filing of the DSP. As part of these

stakeholder meetings, the utility shall solicit input on future programs and/or pilots and solicit feedback on both the hosting capacity analysis and the web portal. The utility shall make all reasonable efforts to engage local governments and community organizations representing disproportionately impacted communities. The Commission may, at its discretion, require utilities to host stakeholder discussions regarding specific DSP topics.

3529. Contents of the Distribution System Plan.

(a) The utility shall file a Phase I DSP with the Commission that contains the information specified below. When required by the Commission, the utility shall provide any relevant studies, additional data, and work-papers to support the information contained in the plan. The DSP shall include the following:

(I) 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;

(II) a description of how the distribution grid may evolve over the next five and ten years due to various factors, such as increasing DER penetration, the expansion of beneficial electrification programs and other electrification, advanced metering infrastructure, increasing demand flexibility, energy efficiency and other emerging technologies. The utility should discuss the challenges and opportunities presented by the emergence of new technology as well as plans they have to adapt to or utilize these changes to the grid;

(III) 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;

(IV) distribution system forecasts, as described in rule 3530;

(V) an assessment of the existing distribution system, as described in rule 3531;

(VI) an assessment of grid needs, as described in rule 3532;

(VII) a description of grid innovations and any proposed pilots and programs, as described in rule 3533;

(VIII) NWA suitability screening results, as described in rule 3534;

(IX) a proposed NWA cost benefit analysis methodology, as described in rule 3535;

(X) any proposed documents and model contracts that the utility intends to use for NWA solicitation or procurement;

(XI) a Phase I action plan, as described in rule 3536;

(XII) a proposal for cost recovery, which may include an incentive, as described in rule 3538;

(XIII) a security assessment, as described in rule 3539.

(XIV) a proposal for implementation of a web portal as described in paragraph 3541(d);

(XV) a description of the stakeholder engagement process, as described in paragraph 3528(g); and

(XVI) 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.

3530. Distribution System Forecasts.

(a) Forecast requirements. The utility shall prepare ~~energy and~~ demand forecasts for each year within the ten-year planning period. The utility shall also prepare ten-year forecasts for load growth on the distribution grid, including the growth of various types of DERs connected to the distribution grid. Forecasts should be based on at least two growth scenarios (State Policy and High), including 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. Forecasted growth should include the following:

(I) peak load growth at each substation, by year;

(II) peak load growth at each substation transformer by year;

(III) peak load growth on each feeder, by year;

(IV) coincident peak and non-coincident peak load growth at substations, transformers, and feeders, by voltage class;

(V) load growth associated with beneficial electrification, by substation transformer and by feeder under each scenario in subparagraph 3530(a)(X);

(VI) load growth due to new planned neighborhoods or housing developments,

(VII) net load impacts due to DER adoption under each scenario in subparagraph 3530(a)(X);

(VIII) net load impacts due to demand side management, demand response, and demand flexibility;

(IX) approved CSG capacity in RES Plans and anticipated CSG capacity additions beyond the current effective RES plans;

(X) forecasts of DERs and NWA should include ten-year scenarios that project expected growth of DERs and NWA, including expected geographic dispersion at the distribution feeder level and impacts on distribution planning. Scenarios shall be designed to meet or exceed current state policy such as those related to greenhouse gas (GHG) reductions, increased use of DERs, electrification, distribution reliability, resiliency, and transmission system needs. Scenarios shall include key inputs including growth of peak exported generation or net generation from distributed solar generation; growth of peak exported generation or net generation from distributed battery storage systems; and growth of peak exported generation or net generation from all other distributed generation. Scenarios shall be based on the following criteria:

(A) State Policy Goal Scenario: Adopts a current forecast case for DER and NWA deployment for distribution planning at the feeder lever, down to each line section, assuming compliance with current state policy goals.

(B) High Growth Scenario: Adopts a high growth case for DERs. This scenario should exceed state policy goals, which may include long-term GHG reductions, and beneficial electrification at levels higher or faster than required in state statute or incurrent state policy goals. Additionally, the High Growth Scenario may improve upon performance in areas of demand flexibility, distribution reliability, resiliency, and transmission system needs beyond a business as usual projection.

(b) The utility shall provide all assumptions and methodologies that are inputs into the forecasting scenarios in paragraph 3530(a).

3531. Assessment of Existing Distribution System.

(a) System overview and substation historical data.

(I) To identify and assess needs on the distribution system, each utility shall provide a map of existing and planned substations within its service territory, as well as tabular information about the current design capacity, and performance of each substation and substation transformer. The assessment should also include the status of advanced metering infrastructure deployment which may be made by reference to other reports or filings. At a minimum, this should include the following information for each substation and substation transformer on the utility's distribution grid:

(A) maximum rated capacity of each substation transformer;

(B) peak hourly demand on each substation transformer for the past three years;

(C) capacity margin for each substation transformer;

(D) advanced functionality capabilities of each substation transformer;

(E) number of feeders served by each substation and substation transformer;

(F) maximum rated capacity of each feeder;

(G) peak hourly demand on each feeder for the past three years;

(H) capacity margin for each feeder;

(I) percentage of grid availability;

(J) minimum daytime load;

(K) aggregate miles of underground and overhead wires, categorized by voltage class;

(L) monitoring capabilities and data collection on the distribution system, such as the substations and feeders for which the utility has real-time supervisory control and data acquisition (SCADA) capability;

(M) amount of distributed generation installed on the system (number of systems and nameplate capacity in kilowatts (kW) by generator types, organized by substation or feeder);

(N) description of NWA on the system, organized by substation or feeder; including annual cost savings and greenhouse gas emissions reductions;

(O) amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours (kW and kWh));

(P) estimated number of EVs and Level 2 and DCFC EV charging stations organized by substation or feeder;

(Q) estimated demand flexibility capacity on the system and historic utilization of those flexibility capabilities;

(R) voltage and power quality data for the past three years; and

(S) location of highly seasonal circuits as defined by subparagraph 3667(a)(IV).

(II) Hosting capacity analysis.

(A) As part of its DSP, each utility shall develop a hosting capacity analysis of the distribution system.

(B) The analysis shall determine the hosting capacity on a particular feeder, feeder section or substation at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

(C) The hosting capacity analysis shall be performed using a load flow analysis and forecasted distribution facilities and their capacity, configuration, loading, and voltage data gathered at the substation, feeder, and primary node levels where available.

(D) The utility shall perform scenario analysis to evaluate hosting capacity need under normal planned contingency, and unplanned contingency conditions, for both the State Policy and High Growth scenario.

(E) The utility shall provide a detailed description of the methods and outcomes it used to perform the hosting capacity analysis.

(F) The hosting capacity analysis shall reflect that which appears in the web portal as described in rule 3541. The utility shall also provide a detailed narrative describing the utility's progress towards advancements to the accuracy and value of the hosting capacity analysis and providing real-time hosting capacity data. This should include a description of how its hosting capacity analysis currently advances customer-sited DER (in particular distributed renewable electric generation and energy storage systems), how the utility anticipates the hosting capacity analysis will aid in identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which the utility anticipates customer benefit stemming from the hosting capacity analysis.

(G) For their first DSP filing, utilities with 500,000 or fewer customers shall provide an Excel spreadsheet (or equivalent format) by feeder of either daily daytime minimum load or, if daytime minimum load is not available, daily peak load with the time granularity specified. If daytime minimum load or daily peak load data are unavailable, the utility shall explain why the data are unavailable.

3532. Grid Needs Assessment.

(a) The utility shall provide a summary analysis of the energy, capacity, ancillary services, and reliability needs and constraints on a utility's distribution system and solutions to those needs.

(b) The grid needs assessment shall include an analysis regarding the suitability of non-wires alternatives to mitigate identified needs and recommendations for the deployment of utility infrastructure upgrade solutions versus the procurement of non-wires alternative solutions to address any identified needs.

(c) The grid needs assessment shall address existing and forecasted needs over a ten-year planning period that could result in a major distribution grid project.

(d) The grid needs assessment shall include each of the following parts.

(I) An assessment of critical needs.

(A) The utility shall provide an assessment of critical capacity and reliability needs that must be addressed within the ten-year planning horizon.

(B) The assessment shall include a review of all planned, proposed and potential major distribution grid projects which will be required to address constraints related to substation transformers and feeders that are forecasted to have insufficient capacity to adequately serve peak load or reliability needs over the next ten years.

(C) The assessment shall be divided into two parts – one detailing short-term needs within zero to three years, and one detailing longer-term needs in four to ten years.

(D) The data used for the assessment shall be provided in megawatt values in tables, in a logical spreadsheet form (both printed and functional Excel spreadsheet formats) and graphically as a map in executable ARC GIS or similar format.

(E) The assessment of critical needs will be provided via the web portal, described in rule 3541. Any notable updates to the web portal should also be made in this section of the DSP.

(F) The assessment shall include a review of the capability of the distribution system and any needs incurred to interconnect approved CSG capacity in the utility's current SGIP queue, the capacity approved in its most recent RES Plan but not yet acquired, and a reasonable expectation of future CSG capacity during the DSP planning period. The assessment shall include an estimate of the potential benefits and costs of infrastructure upgrades which may be identified, as well as any impact broader CSG development, particularly new CSG interconnections off of the transmission network, may have on the distribution system.

(II) The utility's current distribution plan for distribution grid investments, as well as the total capital budget including the past three years and the next five years of projected budget. Budgets shall be broken down by relevant budget categories.

(III) Fast charging locations for electric vehicles. The utility shall use the results of the grid needs assessment to identify locations where substation transformers and feeders have sufficient capacity for hosting multiple direct current fast chargers for electric vehicles. Utilities will also assess vehicle-to-grid (V2G) opportunities as potential NWA projects.

(IV) An identification of any long-term needs identified in the grid needs assessment for which ratable procurement may avoid or defer the anticipated need driven by steady load growth, including geographically targeted deployment of demand flexibility, demand response, and energy efficiency measures.

3533. Grid Innovation.

(a) The DSP shall address DSP pilots and programs that are either in progress, planned, or have been suggested by other parties and found to have merit by the utility. The DSP shall identify any barriers to deployment of DERs and NWA. Such barriers may include but not be limited to integration or interconnection of DERs and NWAs, barriers that limit the ability of a DER and NWA to provide benefits, and barriers related to distribution system operation and infrastructure capability. This section shall include, but not be limited to:

(I) Within each DSP, the utility may propose new pilots and programs designed to gain experience integrating DER, NWA or other new distribution technologies in a way that improves system performance, minimizes system costs, increases system resiliency and/or reliability, and/or reduces greenhouse gas emissions including from reduced curtailment of renewable energy. Such pilots and programs may be proposed as solutions to help solve identified grid needs identified under rule 3532.

(II) New proposed pilots. Within each DSP, the utility may propose new pilots. Pilots shall not be required to pass a cost-benefit test; however, the Commission shall determine that the pilot can be implemented at a reasonable cost and rate impact. Each of the proposed pilots shall, at a minimum, include:

(A) a description of what the utility seeks to learn through the pilot with specific goals and metrics;

(B) an explanation of how the pilot can be scaled to enable the utility to achieve objectives described in the plan pursuant to rule 3529;

(C) the specific DER and NWA technology or technologies eligible for the pilot, including any operational requirements;

(D) a description of any geographic or locational focus of the pilot;

(E) the customer classes that may participate in the pilot;

(F) a description of the potential benefits the utility expects the pilot technology to demonstrate;

(G) a description of the costs of the pilot, including a cap on costs for each pilot;

(H) criteria for evaluation of the pilot and an evaluation plan that includes a calculation of pilot costs, schedule, and a summary of pilot benefits, including quantified benefits, as available;

(I) a description of the use of any targeted incentive payments, or other incentives, provided to participants;

(J) a description of the mechanism to acquire equipment, technologies, vendors, and participants in the pilot; and

(K) a description of how the pilot will provide health, safety, environmental, or financial benefits to disproportionately impacted communities.

(III) New proposed programs. Within its DSP, the utility may seek approval for a new program to better integrate DER and NWA or other distribution technologies into its business practices in a way that improves system performance, minimizes costs, increases system resiliency and reliability, or reduces emissions. Proposed programs may be successors of completed pilots; however, a utility does not need to have conducted a pilot in order to seek approval for a new program.

(IV) The utility may propose pilots or programs developed internally and shall also accept third-party proposals for pilots and programs at any time. For a third-party pilot or program to be considered in a DSP, it must be received by the utility at least six months prior to the DSP filing deadline. 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. For any proposal not considered, the utility shall explain why it was not considered.

(V) Updates on existing pilots and programs. Within its DSP, the utility shall provide a narrative status update on all active pilots and programs approved in prior DSPs. The utility may also seek reauthorization of existing programs within a DSP. As part of its first DSP, the utility is encouraged to evaluate whether any existing reporting obligations outside the DSP related to distribution system pilots, programs, or projects should be centralized within the DSP process. Upon Commission approval, and notice filed within the original proceeding, such reporting obligations shall be transferred to DSP proceedings.

(b) NWAs and pilots may include the use of targeted incentive payments to encourage DER adoption or optimize the use of existing DERs by customers in specific locations, to provide locational value to the system. Such incentives shall be accounted for in the cost benefit analysis as described in rule 3535 and shall be recovered in a manner similar to other distribution-grid related expenditures.

3534. NWA Suitability Screening.

(a) Major distribution grid projects identified to be necessary in the grid needs assessment conducted pursuant to rule 3532 shall be subject to an NWA suitability screening to determine if a NWA may be a suitable alternative to traditional utility infrastructure solutions.

(b) The NWA suitability screening is performed by the utility and includes the following criteria:

(I) the project is anticipated to occur during the ten-year planning horizon;

(II) the constraint is due to thermal loading, voltage, capacity or reliability issues and could be resolved by a DER, a reduction in peak demand loading, a reduction in energy consumption, or load shifting on the transmission or distribution facilities; and

(III) the conventional solution is still within the planning or design stage, with no major equipment on order, received, or installed that cannot be repurposed for other uses.

(c) The utility may seek a waiver from these requirements on a case-by-case basis, if necessary, to preserve reliability, serve economic development needs, or to meet other unforeseen circumstances where the utility expects a non-wires alternative cannot adequately resolve or the planning constraint. Such requests should be substantiated to show why the NWA suitability screening is not possible or could not reasonably result in an alternative to traditional utility infrastructure. Should the utility assert that a NWA is infeasible due to the urgency of the grid need, the utility shall also explain why the grid need was not previously identified.

(d) For all major distribution grid projects identified as meeting all the NWA suitability screening, the utility shall conduct a technology-neutral competitive solicitation for NWAs to defer, reduce, or avoid the costs of the major distribution grid projects.

3535. NWA Cost Benefit Analysis.

(a) In order to assess the cost-effectiveness of a potential NWA solution that meets the NWA Suitability Screening in rule 3534, the utility shall:

(I) develop and publish a cost benefit methodology that will be provided in the utility's DSP;

(II) assess the proposed NWA solution using a cost-benefit methodology that considers the approach as put forward in the National Standard Practice Manual and specifically including the following costs and benefits: avoided or deferred costs associated with an NWA solution, sub-transmission, substation transformer additions or upgrades, feeder capital and operating costs, distribution power quality equipment, reliability and resiliency costs, energy and capacity value of generation, capacity value of storage, greenhouse gas emissions including the Commission approved social cost of carbon useful life of NWA and traditional solutions, and dispatchability and availability of the technology. If the utility is proposing a performance incentive as part of cost recovery for the NWA pursuant to paragraph 3538(d), it shall include the cost-benefit analysis both with and without the performance incentive included as a cost of the project;

(III) provide a description of DSP goals, compliance with statute, rules, and requirements, and additional relevant principles; and

(IV) assess the proposed distribution system costs, direct system benefits, indirect system benefits, and system sensitivity analysis.

(b) The utility may also propose an alternative or adjusted cost-benefit methodology if it does not believe that the full costs and benefits of the NWA solution are being counted.

3536. Action Plan.

(a) The utility shall provide a five-year action plan for distribution system investments and activities within its Phase I DSP which will serve as an application ~~report~~ for the Commission and stakeholders to rely upon when evaluating distribution system planning projects, pilots, and programs.

(b) The Phase I action plan shall include the sequence of events and timelines for each action that will not require a solicitation process following Phase I, including:

(I) the implementation of NWAs to address grid needs not classified as major distribution system projects, and the implementation of NWAs approved in prior DSPs;

(II) the implementation of proposed pilots and programs as specified in rule 3533;

(III) the implementation of major distribution grid projects that were determined to be the best option to address grid needs;

(IV) system interoperability and communications strategy;

(V) costs and plans associated with obtaining data necessary for the evaluation of NWAs, pilots and programs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles);

(VI) interaction of planned or proposed investments with other utility programs and the effects on existing utility programs and tariffs; and

(VII) the implementation of major distribution projects intended to cost-effectively interconnect the approved and reasonably forecasted CSG capacity, including that approved by RES Plans in effect during the planning period;

(c) Subject to paragraph 3528(b), the utility shall provide an updated action plan with its Phase II DSP. This plan shall include the sequence of events and timelines for NWAs identified in the solicitation process, including:

(I) the implementation of NWAs identified through the NWA analysis process;

(II) an updated system interoperability and communications strategy;

(III) costs and plans associated with obtaining data necessary for the evaluation of NWAs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles); and

(IV) interaction of planned or proposed NWA investments with other utility programs and the effects on existing utility programs and tariffs.

3537. NWA Solicitation Process (Phase II).

(a) The utility shall propose in its DSP (Phase I) Application appropriate timelines for the release of the RFP(s), the receipt of bids, evaluation of bids, the utility's proposal to the Commission, the filing of the independent evaluator report, party comments in response to the independent evaluator report, and the Commission decision. These timelines should consider similar timelines as expressed in the Electric Resource Planning Rules, specifically rule 3613. The timelines proposed by the utility and approved by the Commission in the DSP (Phase I) shall describe an appropriately expedited, comment-based NWA Solicitation Process (Phase II) to facilitate timely decisions and implementation of NWA bids.

(b) For projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria, an Independent Evaluator (IE) shall be retained.

(I) The utility shall file for Commission approval the name of the independent evaluator. The Commission shall approve an independent evaluator by written decision during Phase I.

(II) The utility shall pay for the services provided by the independent evaluator pursuant to a contract approved by the Commission. In its Phase I DSP Application, the utility shall

specify the level and structure of any bid fees proposed to offset the independent evaluator and solicitation costs. The terms of such contract shall prohibit the independent evaluator from assisting any entity making proposals to the utility for subsequent resource acquisitions for three years.

(III) The utility shall work cooperatively with the independent evaluator and shall provide the independent evaluator immediate and continuing access to all documents and data reviewed, used, or produced by the utility in the preparation of its projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria and in its bid solicitation, evaluation, and selection processes. The utility shall make available the appropriate utility staff to meet with the independent evaluator to answer questions and, if necessary, discuss the prosecution of work. The utility shall provide to the independent evaluator, in a timely manner to facilitate the deadlines outlined in these rules, bid evaluation results and modeling runs so that the independent evaluator can verify these results and can investigate options that the utility did not consider. If the independent evaluator notes a problem or a deficiency in the bid evaluation process, the independent evaluator should notify the utility.

(IV) All parties in the DSP proceeding other than the utility are restricted from initiating contacts with the independent evaluator. The independent evaluator may initiate contact with the utility and other parties. For all contacts with parties in the DSP proceeding, including those with the utility, the independent evaluator shall maintain a log that briefly identifies the entities communicating with the independent evaluator, the date and duration of the communication, the means of communication, the topics discussed, and the materials exchanged, if any.

(V) The independent evaluator shall generally serve as an advisor to the Commission and shall generally not be a party to the proceedings. As such, the independent evaluator shall not be subject to discovery and cross-examination at hearing.

(VI) Within 30 days of a utility selecting an NWA bidder to advance to Phase II, the independent evaluator shall file a report. The independent evaluator shall address in its report whether the utility's competitive acquisition procedures and bidding policy, including the assumptions, criteria and models, were sufficient to solicit and evaluate bids in a fair and reasonable manner, with any deficiencies specifically noted. The independent evaluator shall provide confidential versions of these reports to Commission staff and the UCA.

(c) All solicitations, unless requested by the Commission, or requested by the utility and approved by the Commission, shall be conducted in a technology neutral manner.

(d) The utility may require prospective bidders to sign non-disclosure agreements to obtain information deemed confidential or highly confidential.

(e) After final NWA bids have been selected by the utility, the utility shall update the elements of the Action Plan that pertain to NWAs.

3538. Approvals and Cost Recovery.

(a) The utility may seek Commission approval of a NWA, pilot, or program in its DSP application filing. Should such an approval be sought, the Commission may require a hearing specifically on the NWA pilot, or program in addition to the process described in rule 3536. The Commission may require the utility to demonstrate satisfactory compliance with appropriate benchmarks or performance metrics outlined in the Commission's decision approving pilots, programs or NWA or other components of the DSP. Utilities may seek approval to implement an NWA, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation. New pilots or programs should meet the standards and requirements set forth in paragraph 3533(a).

(b) A utility may seek any necessary approvals for a NWA, pilot or program in other proceedings, including, but not limited to:

(I) demand side management planning;

(II) renewable energy standard compliance planning;

(III) transportation electrification planning; or

(IV) innovative technology pilot programs or demonstrations;

(c) 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. 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 reasonable. The utility may seek approval to implement NWAs, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation.

(d) In the application for approval of a DSP, the utility shall address how it anticipates recovering costs associated with the investments put forward in its DSP in accordance with subparagraph 3529(a)(XI).

(I) Investments made to implement an approved DSP shall be deemed to made in the ordinary course of business and shall be recovered through the normal implementation of the utilities rate mechanisms.

(II) The utility shall demonstrate that the investments made to implement an approved DSP do not undermine equitable access to other utility programs and do not materially impact the related utility program's targeted performance.

(III) The utility may propose a performance incentive for implementing any NWA, pilot, or program as a component of its cost recovery proposal. The performance mechanism, if proposed, shall also be included as part of the cost-benefit analysis specified in rule 3535. A performance incentive may include allocating to the utility a share of the cost-savings derived from NWA implementation as compared to the avoided capital investment.

(IV) For costs the Commission deems to be incurred outside the ordinary course of business, the utility may seek approval of a regulatory asset for recovery as part of the utility's next rate case, or may be placed in another cost recovery mechanism as proposed by the utility. The Commission shall establish the authorized rate of return on any regulatory asset created pursuant to this paragraph.

(e) 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.

(f) The utility shall file a final DSP, which may include required modifications, within 60 days of the Commission's final decision.

3539. Security Assessment.

(a) The utility shall provide a narrative assessment of the reliability and resilience of the distribution grid with respect to cybersecurity and physical security, including:

(I) current status of distribution grid reliability and plans for improving reliability, including areas of the grid where reliability problems have been identified, with plans for resolving them. Distribution grid reliability metrics (SAIDI and SAIFI at a minimum) should be provided for each year for the past three years for each substation;

(II) list of major outages, including cause and duration, involving 10,000 customers or more for each year for the past three years;

(III) analysis of cyber security issues or other threats to the distribution system and what efforts the utility is taking to ensure the distribution system is secure;

(IV) analysis of risks by substation posed by natural disasters such as wildfires, floods, severe storms, and a detailed description of efforts the utility is taking to increase system resiliency in the response to these risks;

(V) other plans aimed at improving distribution system resiliency; and

(VI) any pilots or programs, existing or proposed, aimed at increasing reliability and resiliency, using microgrids or other technology, should be discussed within the Grid Innovation section of the Phase I DSP, as described in rule 3533.

(VII) The utility may incorporate by reference any other filings or applications made to the Commission that are relevant to a discussion of distribution system reliability and resilience.

3540. Data Access, Privacy and Confidentiality.

(a) The utility shall disclose data necessary to implement these rules with appropriate levels of protection, considering sensitivity and public benefit. The utility shall identify and address the

treatment of sensitive information in consideration of the objectives of DSP and as required by these rules.

(b) The utility shall not disclose personal information, as defined in paragraph 1004(x), or customer data, as defined in paragraph 3001(i). Paragraph 3033(b) shall not apply to data releases under this rule.

(c) In each DSP application filing made pursuant to rule 3529, the utility shall file a list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information that the utility claims is highly confidential, and its proposed treatment of the information. For good cause shown the utility may seek to protect information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

3541. Web Portal.

(a) The utility shall make available a web portal that provide map-based and tabular data that is publicly available or access-restricted as further defined under this rule. Such web portal shall be designed to meet the objectives of the DSP and shall allow users to download data in tabular and geospatial formats

(b) The utility may only deny access to its web portal if visitors and/or registrants violate the terms of service or other agreed upon terms of access. To ensure the appropriate level of protection of sensitive information, the utility may require visitors to the web portal to take actions, including:

(I) requiring visitors to acknowledge terms of service associated with its use, provided those terms do not preclude academic or public policy purposes; and

(II) establishing registration processes, including the creation of a username and password, and/or the use of multifactor authentication for access to sensitive information.

(c) A web portal shall include at least the following information:

(I) consistent with subparagraph 3531(a)(II), the utility's hosting capacity analysis;

(II) publicly available summaries, data, or links to existing information on the utility's website related to programs approved by the Commission that address the deployment of DERs, including, without limitation, pilots, tariffs, and incentives; and

(III) any additional content as directed by the Commission.

(d) Implementation of the web portal.

(I) Prior to filing its first DSP application pursuant to rule 3529, the utility shall engage potential users of the web portal from multiple sectors to develop a proposal for implementation of the web portal to be filed with the application.

(II) In its first DSP application pursuant to rule 3529, the utility shall present a proposal and timeline for developing a web portal that meets the requirements of this rule and includes:

(A) a summary of its process for identifying and engaging potential users of the web portal and the results of that process;

(B) a description of use cases that will be implemented through the web portal to meet the objectives of DSP;

(C) an evaluation of the data required in a DSP application pursuant to rule 3529 that addresses what data will be provided on the web portal and at what level of granularity, an evaluation of the risks and benefits associated with providing such data, proposals for treatment of sensitive information, and identifying any data for which confidential or highly confidential treatment is sought under the process provided in paragraph 3540(c);

(D) a proposal for providing functionalities that enhance the user experience, such as color-coding of substations, circuits, and feeders or ability to change the year of the data being displayed;

(E) a proposal for what information is currently available and can be provided on a web portal and what information requires approval by the Commission for incorporation onto a web portal;

(F) a proposal for updating data provided through the web portal, specifically addressing the quarterly updating of the utility's hosting capacity analysis as described in subparagraph 3531(a)(II);

(G) a proposal for enabling Application Programming Interface (API) capabilities where reasonable and appropriate; and

(H) a proposal for collecting user feedback on an ongoing basis.

(III) In subsequent DSP application proceedings, the utility shall provide an update on the status of implementing the web portal and any proposed changes to functionality and treatment of data. Prior to each application pursuant to rule 3529, the utility is encouraged to engage with stakeholders including users of the web portal, to identify changes.

(IV) The utility shall file an annual compliance report in the most recent DSP application proceeding that provides an update on the status of implementing the web portal, summarizes user feedback, and describes how the utility addressed that feedback, including any updates or revisions to the functionality of the web portal that are anticipated to occur prior to its next DSP application filing.

3542. Evaluation and Reporting.

(a) An assessment of the existing distribution system, as described in rule 3531.

(b) An assessment of Distribution Grid Security, as described in rule 3539.

(c) Starting with its second DSP application, the utility shall describe the 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.

(d) The utility shall report lessons learned from the DSP process and identify ways to improve methodologies through research before the next filing.

(e) Should the utility receive approval for an NWA, a DSP related pilot, or a DSP-related program in a proceeding other than a DSP application, for active projects the utility shall provide in subsequent DSPs:

(I) the name of the project;

(II) a brief description of the project;

(III) the number of the proceeding in which the utility is seeking or has received approval for the project;

(IV) the number(s) of any other proceedings that contain reporting for the project;

(V) the date of project approval, if applicable;

(VI) the total proposed or approved budget; and

(VII) a description of the proposed or approved budget by funding source.

3543. – 3549. [Reserved].

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

3506. – 3524. [Reserved].

DISTRIBUTION SYSTEM PLANNING

3525. Applicability

This rule shall apply to all electric utilities in the state of Colorado that own distribution facilities except municipally owned electric utilities and cooperative electric associations that have voted to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-104, C.R.S.

3526. Overview and Purpose.

The purpose of these rules, as directed by § 40-2-132, C.R.S., is to require electric utilities to file a Distribution System Plan (DSP) that enables the Commission to review and evaluate the utility's investments in the distribution grid to ensure that they cost-effectively support grid adequacy, reliability and resilience and prepare for new expectations upon the distribution system, while simultaneously ensuring progress toward priorities highlighted by state legislation, including but not limited to supporting diversification of energy supply through distributed energy resources, expanding the utilization of non-wire alternatives that may reduce the need for conventional distribution grid investment, reducing greenhouse gas emissions, advancing building and transportation electrification, maintaining affordable customer rates, and promoting equity with regard to disproportionately impacted communities. These rules should also establish a proactive and transparent process for enhancing understanding of key distribution system characteristics.

3527. Definitions.

The following definitions apply to rules 3525 through 3542. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Ancillary services" means the functions that maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event. Ancillary services include but are not limited to synchronized regulation, contingency reserves, flexibility reserves, voltage and frequency response, power factor corrections, and spinning reserves.

(b) “Capacity need” means a distribution grid capacity constraint or shortfall projected within a ten-year period.

(c) “Demand flexibility” means the ability to help utilities manage or balance load by shifting electricity use across hours of the day to reshape customer load profiles or dynamically respond to system conditions while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality and delivering net benefits to the system, customers, or society. Demand flexibility often uses distributed energy resources, communication and/or control technologies.

(d) “Demand response measures” or “demand response” or “DR” means any modulation in customer electric usage at targeted times, including reduction of usage or shifting of usage from one time to another, or interruption or curtailment of electric usage, either with load control equipment or in response to incentives, a signal, or changes in the price of electricity designed to induce changes in electricity use at specific times.

(e) “Direct current fast charger” means a high-power fast charging method of at least 50 kW capacity used to resupply an electric vehicle using direct current electricity, typically 208/480V three-phase.

(f) “Distributed energy resources” or “DER” may include, but are not limited to, distributed generation, energy storage systems, electric vehicles, microgrids, fuel cells, and demand side management measures including energy efficiency, demand response, and demand flexibility that are deployed at the distribution grid level, on either the customer or utility side of the meter. DER can be used to optimize energy use and generation to satisfy the energy, capacity, or ancillary service needs of the distribution grid.

(g) “Distribution system plan” or “DSP” means the compliance plan filed in accordance with rule 3528.

(h) “Energy efficiency measures” are measures that target consumer behavior, equipment, or devices that result in the decrease in electricity usage of customers without detriment to end-use services.

(i) “Grid availability” means the hours per year when the utility makes the grid or a portion of the grid available for use not only by load but also by distributed generation and demand response.

(j) “Grid need” means the need for energy, capacity, ancillary services, reliability, or resiliency services to address a forecasted deficiency on the electric distribution system.

(k) “Hosting capacity” means 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.

(l) “Locational value” means an analysis of distributed energy resources that incorporates location-specific incremental net benefits to the electric grid.

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

(n) "Microgrid" means a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that can act as a single controllable entity with respect to the grid. A microgrid is capable of connecting and disconnecting from the centralized grid to enable the microgrid to operate in both grid-connected or island-mode.

(o) "N-1 event" means an outage event of one distribution or transmission element such as a transformer, feeder, or transmission line that may cause load to shift to other elements as backup. An N-1 event indicates a need for additional reliability capacity if it is determined to cause a potential overload on elements carrying energy to accommodate the event.

(p) "Non-Wires Alternative" or "NWA" means the strategic deployment of distributed energy resources by a utility or a third party and associated control or aggregation of systems and technologies intended to cost-effectively defer or avoid the need for Major Distribution Grid Projects. An NWA is intended to reliably reduce load, congestion or other constraints at times of peak demand in targeted locations on the grid. NWAs can include one or multiple DER, including but not limited to demand response measures, energy efficiency, energy storage, and distributed generation. NWA projects can include these and other investments individually or in combination to meet the specified need.

(q) "Pilot" means a utility offering to test a new use or deployment of DER for a set period of time with a specified end date and number of customers, wherein the utility seeks to gain experience or expertise, and to inform the Commission.

(r) "Program" means an ongoing, long-term offering by the utility with no specified end date that utilizes or deploys DER on the distribution grid in a manner that provides system benefits or cost savings.

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

(t) "Reliability need" means a risk of failure requiring mitigation due to inadequate capacity or voltage support, or an N-1 event on the distribution grid.

(u) "Resilience" is the ability of the distribution grid to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.

3528. Distribution System Plan Filing Requirements.

A utility with over 500,000 customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2022. A utility with 500,000 or fewer customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2023.

(a) Each DSP application filing shall conform to the application requirements contained in rules 3002 and rule 1303 of the Commission's Rules of Practice and Procedure.

(b) Within 30 days of the filing of the application, the Commission shall issue a decision addressing whether the contents of the DSP meet Commission standards based on the information provided by the utility set forth in paragraph 3528(d).

(c) If the DSP identifies major distribution grid projects that meet the NWA suitability screening criteria put forth in paragraph 3534(a), then the DSP proceeding shall consist of two phases.

(I) Within the same proceeding and subject to paragraph 3528(b), the utility shall file a Phase II DSP within 120 days of the filing of the Commission's order establishing the final Phase I DSP.

(A) Within 30 days after the filing of the Phase II DSP, parties may submit comments pertaining to the Phase II DSP.

(B) Within 15 days after the deadline for initial comments on the Phase II DSP, parties may submit reply comments.

(d) If the utility claims that any of the requirements set forth in rules 3529 through 3541 are not yet practicable to provide or are currently cost-prohibitive to provide, the utility shall indicate for each requirement:

(I) why the information is not yet practicable or is currently cost-prohibitive, what information could be provided in the alternative and how that alternative information would achieve planning and policy objectives.

(II) how the information could be obtained in future filings, and if so, at what estimated cost, and on what timeframe;

(III) what the benefits or limitations of filing the data in future reports would be as related to achieving the planning and policy objectives; and

(IV) if the information cannot be provided in future reports, what information could be provided in the alternative and how it would achieve planning and policy objectives.

(e) The utility shall file a final DSP action plan in accordance with rule 3536, including all required modifications, within 60 days of the Commission's final decision.

(f) The utility may file, at any time, an application to amend the contents of a DSP approved pursuant to paragraph 3536(c). Such an application shall meet the requirements of paragraphs 3002(b) and 3002(c), shall identify each proposed amendment, shall state the reason for each proposed amendment, and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

(g) Utilities are encouraged to convene regular, informal stakeholder meetings to discuss DSP-related issues and to inform the contents of DSP applications. The utility shall convene at least one stakeholder meeting at least 90 days prior to the filing of the DSP. As part of these

stakeholder meetings, the utility shall solicit input on future programs and/or pilots and solicit feedback on both the hosting capacity analysis and the web portal. The utility shall make all reasonable efforts to engage local governments and community organizations representing disproportionately impacted communities. The Commission may, at its discretion, require utilities to host stakeholder discussions regarding specific DSP topics.

3529. Contents of the Distribution System Plan.

(a) The utility shall file a Phase I DSP with the Commission that contains the information specified below. When required by the Commission, the utility shall provide any relevant studies, additional data, and work-papers to support the information contained in the plan. The DSP shall include the following:

(I) 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;

(II) a description of how the distribution grid may evolve over the next five and ten years due to various factors, such as increasing DER penetration, the expansion of beneficial electrification programs and other electrification, advanced metering infrastructure, increasing demand flexibility, energy efficiency and other emerging technologies. The utility should discuss the challenges and opportunities presented by the emergence of new technology as well as plans they have to adapt to or utilize these changes to the grid;

(III) 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;

(IV) distribution system forecasts, as described in rule 3530;

(V) an assessment of the existing distribution system, as described in rule 3531;

(VI) an assessment of grid needs, as described in rule 3532;

(VII) a description of grid innovations and any proposed pilots and programs, as described in rule 3533;

(VIII) NWA suitability screening results, as described in rule 3534;

(IX) a proposed NWA cost benefit analysis methodology, as described in rule 3535;

(X) any proposed documents and model contracts that the utility intends to use for NWA solicitation or procurement;

(XI) a Phase I action plan, as described in rule 3536;

(XII) a proposal for cost recovery, which may include an incentive, as described in rule 3538;

(XIII) a security assessment, as described in rule 3539.

(XIV) a proposal for implementation of a web portal as described in paragraph 3541(d);

(XV) a description of the stakeholder engagement process, as described in paragraph 3528(g); and

(XVI) 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.

3530. Distribution System Forecasts.

(a) Forecast requirements. The utility shall prepare demand forecasts for each year within the ten-year planning period. The utility shall also prepare ten-year forecasts for load growth on the distribution grid, including the growth of various types of DERs connected to the distribution grid. Forecasts should be based on at least two growth scenarios (State Policy and High), including 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. Forecasted growth should include the following:

(I) peak load growth at each substation, by year;

(II) peak load growth at each substation transformer by year;

(III) peak load growth on each feeder, by year;

(IV) coincident peak and non-coincident peak load growth at substations, transformers, and feeders, by voltage class;

(V) load growth associated with beneficial electrification, by substation transformer and by feeder under each scenario in subparagraph 3530(a)(X);

(VI) load growth due to new planned neighborhoods or housing developments,

(VII) net load impacts due to DER adoption under each scenario in subparagraph 3530(a)(X);

(VIII) net load impacts due to demand side management, demand response, and demand flexibility;

(IX) approved CSG capacity in RES Plans and anticipated CSG capacity additions beyond the current effective RES plans;

(X) forecasts of DERs and NWA should include ten-year scenarios that project expected growth of DERs and NWA, including expected geographic dispersion at the distribution feeder level and impacts on distribution planning. Scenarios shall be designed to meet or exceed current state policy such as those related to greenhouse gas (GHG) reductions,

increased use of DERs, electrification, distribution reliability, resiliency, and transmission system needs. Scenarios shall include key inputs including growth of peak exported generation or net generation from distributed solar generation; growth of peak exported generation or net generation from distributed battery storage systems; and growth of peak exported generation or net generation from all other distributed generation. Scenarios shall be based on the following criteria:

(A) State Policy Goal Scenario: Adopts a current forecast case for DER and NWA deployment for distribution planning at the feeder lever, down to each line section, assuming compliance with current state policy goals.

(B) High Growth Scenario: Adopts a high growth case for DERs. This scenario should exceed state policy goals, which may include long-term GHG reductions, and beneficial electrification at levels higher or faster than required in state statute or incurrent state policy goals. Additionally, the High Growth Scenario may improve upon performance in areas of demand flexibility, distribution reliability, resiliency, and transmission system needs beyond a business as usual projection.

(b) The utility shall provide all assumptions and methodologies that are inputs into the forecasting scenarios in paragraph 3530(a).

3531. Assessment of Existing Distribution System.

(a) System overview and substation historical data.

(I) To identify and assess needs on the distribution system, each utility shall provide a map of existing and planned substations within its service territory, as well as tabular information about the current design capacity, and performance of each substation and substation transformer. The assessment should also include the status of advanced metering infrastructure deployment which may be made by reference to other reports or filings. At a minimum, this should include the following information for each substation and substation transformer on the utility's distribution grid:

(A) maximum rated capacity of each substation transformer;

(B) peak hourly demand on each substation transformer for the past three years;

(C) capacity margin for each substation transformer;

(D) advanced functionality capabilities of each substation transformer;

(E) number of feeders served by each substation and substation transformer;

(F) maximum rated capacity of each feeder;

(G) peak hourly demand on each feeder for the past three years;

(H) capacity margin for each feeder;

(I) percentage of grid availability;

(J) minimum daytime load;

(K) aggregate miles of underground and overhead wires, categorized by voltage class;

(L) monitoring capabilities and data collection on the distribution system, such as the substations and feeders for which the utility has real-time supervisory control and data acquisition (SCADA) capability;

(M) amount of distributed generation installed on the system (number of systems and nameplate capacity in kilowatts (kW) by generator types, organized by substation or feeder);

(N) description of NWA on the system, organized by substation or feeder; including annual cost savings and greenhouse gas emissions reductions;

(O) amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours (kW and kWh));

(P) estimated number of EVs and Level 2 and DCFC EV charging stations organized by substation or feeder;

(Q) estimated demand flexibility capacity on the system and historic utilization of those flexibility capabilities;

(R) voltage and power quality data for the past three years; and

(S) location of highly seasonal circuits as defined by subparagraph 3667(a)(IV).

(II) Hosting capacity analysis.

(A) As part of its DSP, each utility shall develop a hosting capacity analysis of the distribution system.

(B) The analysis shall determine the hosting capacity on a particular feeder, feeder section or substation at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

(C) The hosting capacity analysis shall be performed using a load flow analysis and forecasted distribution facilities and their capacity, configuration, loading, and voltage data gathered at the substation, feeder, and primary node levels where available.

(D) The utility shall perform scenario analysis to evaluate hosting capacity need under normal planned contingency, and unplanned contingency conditions, for both the State Policy and High Growth scenario.

(E) The utility shall provide a detailed description of the methods and outcomes it used to perform the hosting capacity analysis.

(F) The hosting capacity analysis shall reflect that which appears in the web portal as described in rule 3541. The utility shall also provide a detailed narrative describing the utility's progress towards advancements to the accuracy and value of the hosting capacity analysis and providing real-time hosting capacity data. This should include a description of how its hosting capacity analysis currently advances customer-sited DER (in particular distributed renewable electric generation and energy storage systems), how the utility anticipates the hosting capacity analysis will aid in identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which the utility anticipates customer benefit stemming from the hosting capacity analysis.

(G) For their first DSP filing, utilities with 500,000 or fewer customers shall provide an Excel spreadsheet (or equivalent format) by feeder of either daily daytime minimum load or, if daytime minimum load is not available, daily peak load with the time granularity specified. If daytime minimum load or daily peak load data are unavailable, the utility shall explain why the data are unavailable.

3532. Grid Needs Assessment.

(a) The utility shall provide a summary analysis of the energy, capacity, ancillary services, and reliability needs and constraints on a utility's distribution system and solutions to those needs.

(b) The grid needs assessment shall include an analysis regarding the suitability of non-wires alternatives to mitigate identified needs and recommendations for the deployment of utility infrastructure upgrade solutions versus the procurement of non-wires alternative solutions to address any identified needs.

(c) The grid needs assessment shall address existing and forecasted needs over a ten-year planning period that could result in a major distribution grid project.

(d) The grid needs assessment shall include each of the following parts.

(I) An assessment of critical needs.

(A) The utility shall provide an assessment of critical capacity and reliability needs that must be addressed within the ten-year planning horizon.

(B) The assessment shall include a review of all planned, proposed and potential major distribution grid projects which will be required to address constraints related to substation transformers and feeders that are forecasted to have insufficient capacity to adequately serve peak load or reliability needs over the next ten years.

(C) The assessment shall be divided into two parts – one detailing short-term needs within zero to three years, and one detailing longer-term needs in four to ten years.

(D) The data used for the assessment shall be provided in megawatt values in tables, in a logical spreadsheet form (both printed and functional Excel spreadsheet formats) and graphically as a map in executable ARC GIS or similar format.

(E) The assessment of critical needs will be provided via the web portal, described in rule 3541. Any notable updates to the web portal should also be made in this section of the DSP.

(F) The assessment shall include a review of the capability of the distribution system and any needs incurred to interconnect approved CSG capacity in the utility's current SGIP queue, the capacity approved in its most recent RES Plan but not yet acquired, and a reasonable expectation of future CSG capacity during the DSP planning period. The assessment shall include an estimate of the potential benefits and costs of infrastructure upgrades which may be identified, as well as any impact broader CSG development, particularly new CSG interconnections off of the transmission network, may have on the distribution system.

(II) The utility's current distribution plan for distribution grid investments, as well as the total capital budget including the past three years and the next five years of projected budget. Budgets shall be broken down by relevant budget categories.

(III) Fast charging locations for electric vehicles. The utility shall use the results of the grid needs assessment to identify locations where substation transformers and feeders have sufficient capacity for hosting multiple direct current fast chargers for electric vehicles. Utilities will also assess vehicle-to-grid (V2G) opportunities as potential NWA projects.

(IV) An identification of any long-term needs identified in the grid needs assessment for which ratable procurement may avoid or defer the anticipated need driven by steady load growth, including geographically targeted deployment of demand flexibility, demand response, and energy efficiency measures.

3533. Grid Innovation.

(a) The DSP shall address DSP pilots and programs that are either in progress, planned, or have been suggested by other parties and found to have merit by the utility. The DSP shall identify any barriers to deployment of DERs and NWA. Such barriers may include but not be limited to integration or interconnection of DERs and NWAs, barriers that limit the ability of a DER and NWA to provide benefits, and barriers related to distribution system operation and infrastructure capability. This section shall include, but not be limited to:

(I) Within each DSP, the utility may propose new pilots and programs designed to gain experience integrating DER, NWA or other new distribution technologies in a way that improves system performance, minimizes system costs, increases system resiliency and/or reliability, and/or reduces greenhouse gas emissions including from reduced curtailment of renewable energy. Such pilots and programs may be proposed as solutions to help solve identified grid needs identified under rule 3532.

(II) New proposed pilots. Within each DSP, the utility may propose new pilots. Pilots shall not be required to pass a cost-benefit test; however, the Commission shall determine that the pilot can be implemented at a reasonable cost and rate impact. Each of the proposed pilots shall, at a minimum, include:

(A) a description of what the utility seeks to learn through the pilot with specific goals and metrics;

(B) an explanation of how the pilot can be scaled to enable the utility to achieve objectives described in the plan pursuant to rule 3529;

(C) the specific DER and NWA technology or technologies eligible for the pilot, including any operational requirements;

(D) a description of any geographic or locational focus of the pilot;

(E) the customer classes that may participate in the pilot;

(F) a description of the potential benefits the utility expects the pilot technology to demonstrate;

(G) a description of the costs of the pilot, including a cap on costs for each pilot;

(H) criteria for evaluation of the pilot and an evaluation plan that includes a calculation of pilot costs, schedule, and a summary of pilot benefits, including quantified benefits, as available;

(I) a description of the use of any targeted incentive payments, or other incentives, provided to participants;

(J) a description of the mechanism to acquire equipment, technologies, vendors, and participants in the pilot; and

(K) a description of how the pilot will provide health, safety, environmental, or financial benefits to disproportionately impacted communities.

(III) New proposed programs. Within its DSP, the utility may seek approval for a new program to better integrate DER and NWA or other distribution technologies into its business practices in a way that improves system performance, minimizes costs, increases system resiliency and reliability, or reduces emissions. Proposed programs may be successors of completed pilots; however, a utility does not need to have conducted a pilot in order to seek approval for a new program.

(IV) The utility may propose pilots or programs developed internally and shall also accept third-party proposals for pilots and programs at any time. For a third-party pilot or program to be considered in a DSP, it must be received by the utility at least six months prior to the DSP filing deadline. 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. For any proposal not considered, the utility shall explain why it was not considered.

(V) Updates on existing pilots and programs. Within its DSP, the utility shall provide a narrative status update on all active pilots and programs approved in prior DSPs. The utility may also seek reauthorization of existing programs within a DSP. As part of its first DSP, the utility is encouraged to evaluate whether any existing reporting obligations outside the DSP related to distribution system pilots, programs, or projects should be centralized within the DSP process. Upon Commission approval, and notice filed within the original proceeding, such reporting obligations shall be transferred to DSP proceedings.

(b) NWAs and pilots may include the use of targeted incentive payments to encourage DER adoption or optimize the use of existing DERs by customers in specific locations, to provide locational value to the system. Such incentives shall be accounted for in the cost benefit analysis as described in rule 3535 and shall be recovered in a manner similar to other distribution-grid related expenditures.

3534. NWA Suitability Screening.

(a) Major distribution grid projects identified to be necessary in the grid needs assessment conducted pursuant to rule 3532 shall be subject to an NWA suitability screening to determine if a NWA may be a suitable alternative to traditional utility infrastructure solutions.

(b) The NWA suitability screening is performed by the utility and includes the following criteria:

(I) the project is anticipated to occur during the ten-year planning horizon;

(II) the constraint is due to thermal loading, voltage, capacity or reliability issues and could be resolved by a DER, a reduction in peak demand loading, a reduction in energy consumption, or load shifting on the transmission or distribution facilities; and

(III) the conventional solution is still within the planning or design stage, with no major equipment on order, received, or installed that cannot be repurposed for other uses.

(c) The utility may seek a waiver from these requirements on a case-by-case basis, if necessary, to preserve reliability, serve economic development needs, or to meet other unforeseen circumstances where the utility expects a non-wires alternative cannot adequately resolve or the planning constraint. Such requests should be substantiated to show why the NWA suitability screening is not possible or could not reasonably result in an alternative to traditional utility infrastructure. Should the utility assert that a NWA is infeasible due to the urgency of the grid need, the utility shall also explain why the grid need was not previously identified.

(d) For all major distribution grid projects identified as meeting all the NWA suitability screening, the utility shall conduct a technology-neutral competitive solicitation for NWAs to defer, reduce, or avoid the costs of the major distribution grid projects.

3535. NWA Cost Benefit Analysis.

(a) In order to assess the cost-effectiveness of a potential NWA solution that meets the NWA Suitability Screening in rule 3534, the utility shall:

(I) develop and publish a cost benefit methodology that will be provided in the utility's DSP;

(II) assess the proposed NWA solution using a cost-benefit methodology that considers the approach as put forward in the National Standard Practice Manual and specifically including the following costs and benefits: avoided or deferred costs associated with an NWA solution, sub-transmission, substation transformer additions or upgrades, feeder capital and operating costs, distribution power quality equipment, reliability and resiliency costs, energy and capacity value of generation, capacity value of storage, greenhouse gas emissions including the Commission approved social cost of carbon useful life of NWA and traditional solutions, and dispatchability and availability of the technology. If the utility is proposing a performance incentive as part of cost recovery for the NWA pursuant to paragraph 3538(d), it shall include the cost-benefit analysis both with and without the performance incentive included as a cost of the project;

(III) provide a description of DSP goals, compliance with statute, rules, and requirements, and additional relevant principles; and

(IV) assess the proposed distribution system costs, direct system benefits, indirect system benefits, and system sensitivity analysis.

(b) The utility may also propose an alternative or adjusted cost-benefit methodology if it does not believe that the full costs and benefits of the NWA solution are being counted.

3536. Action Plan.

(a) The utility shall provide a five-year action plan for distribution system investments and activities within its Phase I DSP which will serve as an application for the Commission and stakeholders to rely upon when evaluating distribution system planning projects, pilots, and programs.

(b) The Phase I action plan shall include the sequence of events and timelines for each action that will not require a solicitation process following Phase I, including:

(I) the implementation of NWAs to address grid needs not classified as major distribution system projects, and the implementation of NWAs approved in prior DSPs;

(II) the implementation of proposed pilots and programs as specified in rule 3533;

(III) the implementation of major distribution grid projects that were determined to be the best option to address grid needs;

(IV) system interoperability and communications strategy;

(V) costs and plans associated with obtaining data necessary for the evaluation of NWAs, pilots and programs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles);

(VI) interaction of planned or proposed investments with other utility programs and the effects on existing utility programs and tariffs; and

(VII) the implementation of major distribution projects intended to cost-effectively interconnect the approved and reasonably forecasted CSG capacity, including that approved by RES Plans in effect during the planning period;

(c) Subject to paragraph 3528(b), the utility shall provide an updated action plan with its Phase II DSP. This plan shall include the sequence of events and timelines for NWAs identified in the solicitation process, including:

(I) the implementation of NWAs identified through the NWA analysis process;

(II) an updated system interoperability and communications strategy;

(III) costs and plans associated with obtaining data necessary for the evaluation of NWAs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles); and

(IV) interaction of planned or proposed NWA investments with other utility programs and the effects on existing utility programs and tariffs.

3537. NWA Solicitation Process (Phase II).

(a) The utility shall propose in its DSP (Phase I) Application appropriate timelines for the release of the RFP(s), the receipt of bids, evaluation of bids, the utility's proposal to the Commission, the filing of the independent evaluator report, party comments in response to the independent evaluator report, and the Commission decision. These timelines should consider similar timelines as expressed in the Electric Resource Planning Rules, specifically rule 3613. The timelines proposed by the utility and approved by the Commission in the DSP (Phase I) shall describe an appropriately expedited, comment-based NWA Solicitation Process (Phase II) to facilitate timely decisions and implementation of NWA bids.

(b) For projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria, an Independent Evaluator (IE) shall be retained.

(I) The utility shall file for Commission approval the name of the independent evaluator. The Commission shall approve an independent evaluator by written decision during Phase I.

(II) The utility shall pay for the services provided by the independent evaluator pursuant to a contract approved by the Commission. In its Phase I DSP Application, the utility shall specify the level and structure of any bid fees proposed to offset the independent evaluator and solicitation costs. The terms of such contract shall prohibit the independent evaluator from assisting any entity making proposals to the utility for subsequent resource acquisitions for three years.

(III) The utility shall work cooperatively with the independent evaluator and shall provide the independent evaluator immediate and continuing access to all documents and data reviewed, used, or produced by the utility in the preparation of its projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria and in its bid solicitation, evaluation, and selection processes. The utility shall make available the appropriate utility staff to meet with the independent evaluator to answer questions and, if necessary, discuss the prosecution of work. The utility shall provide to the independent evaluator, in a timely manner to facilitate the deadlines outlined in these rules, bid evaluation results and modeling runs so that the independent evaluator can verify these results and can investigate options that the utility did not consider. If the independent evaluator notes a problem or a deficiency in the bid evaluation process, the independent evaluator should notify the utility.

(IV) All parties in the DSP proceeding other than the utility are restricted from initiating contacts with the independent evaluator. The independent evaluator may initiate contact with the utility and other parties. For all contacts with parties in the DSP proceeding, including those with the utility, the independent evaluator shall maintain a log that briefly identifies the entities communicating with the independent evaluator, the date and duration of the communication, the means of communication, the topics discussed, and the materials exchanged, if any.

(V) The independent evaluator shall generally serve as an advisor to the Commission and shall generally not be a party to the proceedings. As such, the independent evaluator shall not be subject to discovery and cross-examination at hearing.

(VI) Within 30 days of a utility selecting an NWA bidder to advance to Phase II, the independent evaluator shall file a report. The independent evaluator shall address in its report whether the utility's competitive acquisition procedures and bidding policy, including the assumptions, criteria and models, were sufficient to solicit and evaluate bids in a fair and reasonable manner, with any deficiencies specifically noted. The independent evaluator shall provide confidential versions of these reports to Commission staff and the UCA.

(c) All solicitations, unless requested by the Commission, or requested by the utility and approved by the Commission, shall be conducted in a technology neutral manner.

(d) The utility may require prospective bidders to sign non-disclosure agreements to obtain information deemed confidential or highly confidential.

(e) After final NWA bids have been selected by the utility, the utility shall update the elements of the Action Plan that pertain to NWAs.

3538. Approvals and Cost Recovery.

(a) The utility may seek Commission approval of a NWA, pilot, or program in its DSP application filing. Should such an approval be sought, the Commission may require a hearing specifically on the NWA pilot, or program in addition to the process described in rule 3536. The Commission may require the utility to demonstrate satisfactory compliance with appropriate benchmarks or performance metrics outlined in the Commission's decision approving pilots, programs or NWA or other components of the DSP. Utilities may seek approval to implement an NWA, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation. New pilots or programs should meet the standards and requirements set forth in paragraph 3533(a).

(b) A utility may seek any necessary approvals for a NWA, pilot or program in other proceedings, including, but not limited to:

(I) demand side management planning;

(II) renewable energy standard compliance planning;

(III) transportation electrification planning; or

(IV) innovative technology pilot programs or demonstrations;

(c) 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. 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 reasonable. The utility may seek approval to implement NWAs, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation.

(d) In the application for approval of a DSP, the utility shall address how it anticipates recovering costs associated with the investments put forward in its DSP in accordance with subparagraph 3529(a)(XI).

(I) Investments made to implement an approved DSP shall be deemed to made in the ordinary course of business and shall be recovered through the normal implementation of the utilities rate mechanisms.

(II) The utility shall demonstrate that the investments made to implement an approved DSP do not undermine equitable access to other utility programs and do not materially impact the related utility program’s targeted performance.

(III) The utility may propose a performance incentive for implementing any NWA, pilot, or program as a component of its cost recovery proposal. The performance mechanism, if proposed, shall also be included as part of the cost-benefit analysis specified in rule 3535. A performance incentive may include allocating to the utility a share of the cost-savings derived from NWA implementation as compared to the avoided capital investment.

(IV) For costs the Commission deems to be incurred outside the ordinary course of business, the utility may seek approval of a regulatory asset for recovery as part of the utility’s next rate case, or may be placed in another cost recovery mechanism as proposed by the utility. The Commission shall establish the authorized rate of return on any regulatory asset created pursuant to this paragraph.

(e) 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.

(f) The utility shall file a final DSP, which may include required modifications, within 60 days of the Commission's final decision.

3539. Security Assessment.

(a) The utility shall provide a narrative assessment of the reliability and resilience of the distribution grid with respect to cybersecurity and physical security, including:

(I) current status of distribution grid reliability and plans for improving reliability, including areas of the grid where reliability problems have been identified, with plans for resolving them. Distribution grid reliability metrics (SAIDI and SAIFI at a minimum) should be provided for each year for the past three years for each substation;

(II) list of major outages, including cause and duration, involving 10,000 customers or more for each year for the past three years;

(III) analysis of cyber security issues or other threats to the distribution system and what efforts the utility is taking to ensure the distribution system is secure;

(IV) analysis of risks by substation posed by natural disasters such as wildfires, floods, severe storms, and a detailed description of efforts the utility is taking to increase system resiliency in the response to these risks;

(V) other plans aimed at improving distribution system resiliency; and

(VI) any pilots or programs, existing or proposed, aimed at increasing reliability and resiliency, using microgrids or other technology, should be discussed within the Grid Innovation section of the Phase I DSP, as described in rule 3533.

(VII) The utility may incorporate by reference any other filings or applications made to the Commission that are relevant to a discussion of distribution system reliability and resilience.

3540. Data Access, Privacy and Confidentiality.

(a) The utility shall disclose data necessary to implement these rules with appropriate levels of protection, considering sensitivity and public benefit. The utility shall identify and address the treatment of sensitive information in consideration of the objectives of DSP and as required by these rules.

(b) The utility shall not disclose personal information, as defined in paragraph 1004(x), or customer data, as defined in paragraph 3001(i). Paragraph 3033(b) shall not apply to data releases under this rule.

(c) In each DSP application filing made pursuant to rule 3529, the utility shall file a list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information that the utility claims is highly confidential, and its proposed treatment of the information. For good cause shown the utility may seek to protect information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

3541. Web Portal.

(a) The utility shall make available a web portal that provide map-based and tabular data that is publicly available or access-restricted as further defined under this rule. Such web portal shall be designed to meet the objectives of the DSP and shall allow users to download data in tabular and geospatial formats

(b) The utility may only deny access to its web portal if visitors and/or registrants violate the terms of service or other agreed upon terms of access. To ensure the appropriate level of protection of sensitive information, the utility may require visitors to the web portal to take actions, including:

(I) requiring visitors to acknowledge terms of service associated with its use, provided those terms do not preclude academic or public policy purposes; and

(II) establishing registration processes, including the creation of a username and password, and/or the use of multifactor authentication for access to sensitive information.

(c) A web portal shall include at least the following information:

(I) consistent with subparagraph 3531(a)(II), the utility's hosting capacity analysis;

(II) publicly available summaries, data, or links to existing information on the utility's website related to programs approved by the Commission that address the deployment of DERs, including, without limitation, pilots, tariffs, and incentives; and

(III) any additional content as directed by the Commission.

(d) Implementation of the web portal.

(I) Prior to filing its first DSP application pursuant to rule 3529, the utility shall engage potential users of the web portal from multiple sectors to develop a proposal for implementation of the web portal to be filed with the application.

(II) In its first DSP application pursuant to rule 3529, the utility shall present a proposal and timeline for developing a web portal that meets the requirements of this rule and includes:

(A) a summary of its process for identifying and engaging potential users of the web portal and the results of that process;

(B) a description of use cases that will be implemented through the web portal to meet the objectives of DSP;

(C) an evaluation of the data required in a DSP application pursuant to rule 3529 that addresses what data will be provided on the web portal and at what level of granularity, an evaluation of the risks and benefits associated with providing such data, proposals for treatment of sensitive information, and identifying any data for which confidential or highly confidential treatment is sought under the process provided in paragraph 3540(c);

(D) a proposal for providing functionalities that enhance the user experience, such as color-coding of substations, circuits, and feeders or ability to change the year of the data being displayed;

(E) a proposal for what information is currently available and can be provided on a web portal and what information requires approval by the Commission for incorporation onto a web portal;

(F) a proposal for updating data provided through the web portal, specifically addressing the quarterly updating of the utility's hosting capacity analysis as described in subparagraph 3531(a)(II);

(G) a proposal for enabling Application Programming Interface (API) capabilities where reasonable and appropriate; and

(H) a proposal for collecting user feedback on an ongoing basis.

(III) In subsequent DSP application proceedings, the utility shall provide an update on the status of implementing the web portal and any proposed changes to functionality and treatment of data. Prior to each application pursuant to rule 3529, the utility is encouraged to engage with stakeholders including users of the web portal, to identify changes.

(IV) The utility shall file an annual compliance report in the most recent DSP application proceeding that provides an update on the status of implementing the web portal, summarizes user feedback, and describes how the utility addressed that feedback, including any updates or revisions to the functionality of the web portal that are anticipated to occur prior to its next DSP application filing.

3542. Evaluation and Reporting.

(a) An assessment of the existing distribution system, as described in rule 3531.

(b) An assessment of Distribution Grid Security, as described in rule 3539.

(c) Starting with its second DSP application, the utility shall describe the 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.

(d) The utility shall report lessons learned from the DSP process and identify ways to improve methodologies through research before the next filing.

(e) Should the utility receive approval for an NWA, a DSP related pilot, or a DSP-related program in a proceeding other than a DSP application, for active projects the utility shall provide in subsequent DSPs:

(I) the name of the project;

(II) a brief description of the project;

(III) the number of the proceeding in which the utility is seeking or has received approval for the project;

(IV) the number(s) of any other proceedings that contain reporting for the project;

(V) the date of project approval, if applicable;

(VI) the total proposed or approved budget; and

(VII) a description of the proposed or approved budget by funding source.

3543. – 3549. [Reserved].

Decision No. C21-0665

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 20R-0516E

IN THE MATTER OF THE PROPOSED AMENDMENTS TO RULES REGULATING ELECTRIC UTILITIES, 4 CODE OF COLORADO REGULATIONS 723-3, RELATING TO DISTRIBUTION SYSTEM PLANNING.

DECISION GRANTING, AND DENYING, APPLICATIONS FOR REHEARING, REARGUMENT, OR RECONSIDERATION

Mailed Date: October 26, 2021
Adopted Date: October 20, 2021

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I. BY THE COMMISSION

A. Statement

1. Through this Decision, the Commission addresses the Application for Rehearing, Reargument, or Reconsideration of Decision No. C21-0549 (RRR) filed pursuant to § 40-6-114, C.R.S., on September 27, 2021, by rulemaking participant Public Service Company of Colorado (Public Service or Company).

2. Public Service requests the Commission reconsider or clarify certain aspects of Decision No. C21-0549, issued in this rulemaking proceeding on September 7, 2021. By that Decision, the Commission granted, in part, and denied, in part, the exceptions to Recommended Decision No. R21-0287, issued by Hearing Commissioner Megan Gilman on July 8, 2021, and adopted revised rules governing Distribution System Planning (DSP Rules) to implement § 40-2-132, C.R.S. The adopted revised DSP Rules are located within the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* (CCR) 723-3.

3. By this Decision, the Commission grants in part, and denies in part, the RRR filed by Public Service. The final adopted DSP Rules are attached to this Decision in legislative format (*i.e.*, strikeout/underline) as Attachment A, and in final format as Attachment B.

B. Application for RRR

a. NWA Suitability Exemptions (Rules 3532(d)(II)(A), 3534(b)(IV), and 3534(c)

4. In its RRR, Public Service notes Rule 3532(d)(II)(A) was eliminated in the Commission's Decision addressing exceptions in this proceeding (No. C21-0549), primarily based upon a recommendation from Western Resource Advocates (WRA) and the Colorado Energy Office to consolidate three separate provisions related to Non-Wires Alternative (NWA) Suitability Exemptions. The Company disagrees with the interpretation in that Decision, that the

"changes merely consolidate rule language for improved clarification, and also increase the transparency from utilities who request exemptions."[1]

5. Public Service states that while it aims to predict long-term load growth accurately, unanticipated new customer loads (*i.e.*, load that cannot be forecasted) generate requests for new infrastructure that customers expect the Company to serve expediently. This premise was the reason the Company originally requested the Hearing Commissioner adopt a short-term planning exemption in rules for Major Distribution Grid Projects (MGDPs).

6. Public Service states it is concerned that the elimination of Rule 3532(d)(II)(A) could create detrimental impacts which limit economic development, job creation, transportation electrification, and beneficial electrification in the State of Colorado since it would impede and delay the Company from being able to expediently serve any new load which would require system investments above $2 million. The Company also believes there are unintended consequences that eliminating this rule may have on implementing the Company's approved Transportation Electrification Plan programs as potential upcoming Clean Heat Plans.

7. Public Service argues that if left unchanged, consolidated Rule 3534(c) without Rule 3532(d)(II)(A) fundamentally changes the DSP Rules concerning serving short-term and unanticipated customer load requests by requiring utilities to request a waiver for all short-term MGDPs. Public Service further argues that requiring a waiver for all short-term planning needs presumes that all MGDPs, including those which need to be within service within 36 months, are suitable for NWAs. In effect, the requirement for a waiver creates a short-term moratorium on new customer connections. At the same time, the Company states it would either be required to

[1] Public Service's RRR at 4-5. (emphasis omitted)

seek Commission approval of the waiver or conduct an NWA suitability screening and solicitation.

8. Public Services notes that over the past 12 months, it has received several line extension requests to serve the additional loads associated with electrifying fleet vehicles. In at least one of these instances, the distribution system investment costs exceeded the $2 million threshold for an MGDP. Public Services argues that without the short-term exemption language from Rule 3532(d)(II)(A), the Company would have been required to go through the waiver process to meet the customer's expected timelines for that one particular project, with possible conferrals required if the Waiver request is by motion and made in an existing proceeding, as required under Rules 1003 and 1400 of the Rules of Practice and Procedure, 4 CCR 723-1. Therefore, Public Service recommends keeping Rule 3532(d)(II)(A) and Rule 3534(c) as separate rules and adding additional clarification to each rule.

b. Findings and Conclusions

9. The Commission denies Public Service's RRR on this issue. We believe that Public Service has not provided the information needed in this filing to modify the Commission's previous decision. We believe the reinstatement of Rule 3532(d)(II)(A) would give utilities too much leniency in opting out of the NWA assessment process even where an NWA may be viable. We believe utilities must be held accountable to explain decisions or provide the rationale for pursuing conventional projects without evaluating available alternatives.

10. We understand the Company's concern that the waiver process for potential MDGP may slow the process of serving short-term planning needs. But the fact that Public Service could provide only one example from the past year that would have exceeded the $2 Million threshold does not persuade us that these rules need the broad opt-out provision that

Public Service supports. We note that if these short-term planning needs increase in the future due to beneficial electrification efforts, the utility can request a shortened notice period to expedite the process. Additionally, we expect the utilities and stakeholders to become more familiar with projects where an NWA could serve as a legitimate alternative, even for short-term projects such as line extensions.

11. We add that if these projects become more prevalent in the future, and NWAs are not yet suitable alternatives, the utilities can request the Commission promulgate rules to expedite the waiver process explicitly.

c. Rule 3532(d)(I)(F) - Interconnecting Community Solar Gardens

12. In its RRR, Public Service states that certain aspects of Rule 3532(d)(I)(F) could be modified to provide mutually beneficial outcomes to the solar industry and the Company.

13. Public Service states that conducting an assessment for the emphasized portion of the rule is at best a speculative exercise given the lack of locational specificity associated with these future capacities. The Company believes that this requirement focused on future, undefined capacity provides little value to developers and that its belief has subsequently been affirmed through soliciting input from several developers since the Commission issued its Decision No. C21-0549.

14. The Company notes there is a fundamental and material difference between conducting a Grid Needs Assessment for load versus a Grid Needs Assessment for future, non-locationally specific distributed generation (*e.g.*, the total capacity approved in the Renewable Energy Plan, but not yet in the interconnection queue). Public Services argues that specific Community Solar Garden (CSG) locations are not known at the time of approval of a Renewable

Energy Plan, nor will they be known on a forward-looking basis throughout a DSP planning. The Company explains that in the same way that it does not prematurely speculate where the new load will require line extensions to prevent investing in assets that may not be, the Company does not believe that speculating where new CSG development could occur would provide value to the industry or its customers without some level of indication or commitment from developers.

15. Public Service states it has solicited input from several developers following the Commission's Decision Addressing Exceptions. Of the three developers the Company has spoken with directly, there has been universal agreement that the high-level exercise of trying to identify future CSG capacity and associated Grid Needs which is required by Rule 3532(d)(I)(F) would provide little value to the CSG industry. Conversely, the Company and developers have collaboratively identified potential solutions which it believes would create more beneficial and efficient outcomes in the CSG interconnection process.

16. The Company argues that the fundamental issue is that the only way the Company can be reasonably confident in the location of development activity is when a developer applies for interconnection. Therefore, Public Service suggests it continue to work with the industry to explore ways developers could share information with the Company before filing a formal interconnection application. The Company believes this type of transparency could help correct the information asymmetry which exists today and essentially makes the forward-looking requirements, specifically the language bolded above, in Rule 3532(d)(I)(F) impractical.

17. Public Service provides a red line of Rule 3532(d)(I)(F) developed in collaboration with stakeholders. The Company argues that the process for considering many of the improvements and suggestions mentioned above are already contemplated by Rule 3531(a)(II)(F) involving Hosting Capacity Analysis and can be further developed through

the required Stakeholder meetings before the Company filing its first DSP. WRA states that as currently drafted, this rule could be interpreted to allow utilities to offer CSG subscribers the opportunity to retain Renewable Energy Credits but not to require that utilities provide this new offering.

d. Findings and Conclusions

18. The Commission grants Public Service's request to modify Rule 3532(d)(I)(F). We appreciate that Public Service and CSG developers worked together on a suitable solution for all participants. We also note that Pivot Energy filed a letter in support of Public Service's proposed rule language.

19. We agree that this language clarifies the original intent of the rule. More importantly, it encourages a robust stakeholder process to explore ways developers could share information with the Company before filing a formal interconnection application. This type of transparency could help correct the information asymmetry which currently exists.

e. Rule 3530(a)(X)(a) Load Forecasts

20. In its exceptions, Public Service suggested the elimination of "line section" level distribution system load forecasts from Rule 3530(a)(X)(a). In their response to the Company's exceptions, Colorado Solar and Storage Association/Solar Energy Industries Association (COSSA/SEIA) recommended that the Commission maintain this requirement based on an assertion that the Company already provides this level of detail in Minnesota. The Company notes that the attachment provided by COSSA/SEIA, a screenshot of a pop-up dialogue box from the Company's 2021 Minnesota Hosting Capacity Analysis (HCA) map, is separate from the Company's load forecasting process.

21. Public Service believes it is inappropriate to use the separate HCA analysis to justify providing more granular detail in the Company's load forecast. Therefore, the Company requests that the Commission remove the term "line section" from Rule 3530(a)(X)(A) because Public Services states it cannot provide accurate load forecasts at this level of granular detail.

f. Findings and Conclusions

22. The Commission grants Public Services' RRR on this issue. Public Service has clarified that COSSA/SEIA confused the utilities' ability to provide load forecasts at the level of detail that it currently provides in its hosting capacity analysis. We therefore remove the term from Rule 3530(a)(X)(A). We reiterate that the Commission expects this level of detail still to be provided in its updated HCA maps.

g. Miscellaneous Edits and Clarifications

23. Public Service notes two instances of minor errors for correction. In Rule 3530(a)(X)(A), the Company notes that "feeder level" is misspelled as "feeder lever." Additionally, the Company believes a comma is missing between the words "normal" and "planned contingency" in Rule 3531(a)(II)(D). Without adding the comma, this section of the rule implies that the Company only operates under "Normal Planned Contingency" and "Unplanned Contingency" conditions. Public Service believes this section of the rule reflects three scenarios – normal conditions, planned contingency, and unplanned contingency.

h. Findings and Conclusions

24. The Commission grants Public Service's RRR on these two instances.

II. ORDER

A. The Commission Orders That:

1. The Application for Rehearing, Reargument, or Reconsideration of Decision No. C20-0482 filed by Public Service Company of Colorado on September 27, 2021, is granted, and denied, consistent with the discussion above.

2. The final adopted Rules Implementing Distribution System Planning Procedures within the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* 723-3, contained in legislative (*i.e.*, strikeout/underline) format (Attachment A), and final format (Attachment B) are adopted, and are available through the Commission's Electronic Filings system at:

https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=20R-0516E

3. The 20-day time period provided by § 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.

4. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING October 20, 2021.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

JOHN GAVAN

MEGAN M. GILMAN

Commissioners

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

3506. – ~~3549~~3524. [Reserved].

DISTRIBUTION SYSTEM PLANNING

3525. Applicability

This rule shall apply to all electric utilities in the state of Colorado that own distribution facilities except municipally owned electric utilities and cooperative electric associations that have voted to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-104, C.R.S.

3526. Overview and Purpose.

The purpose of these rules, as directed by § 40-2-132, C.R.S., is to require electric utilities to file a Distribution System Plan (DSP) that enables the Commission to review and evaluate the utility's investments in the distribution grid to ensure that they cost-effectively support grid adequacy, reliability and resilience and prepare for new expectations upon the distribution system, while simultaneously ensuring progress toward priorities highlighted by state legislation, including but not limited to supporting diversification of energy supply through distributed energy resources, expanding the utilization of non-wire alternatives that may reduce the need for conventional distribution grid investment, reducing greenhouse gas emissions, advancing building and transportation electrification, maintaining affordable customer rates, and promoting equity with regard to disproportionately impacted communities. These rules should also establish a proactive and transparent process for enhancing understanding of key distribution system characteristics.

3527. Definitions.

The following definitions apply to rules 3525 through 3542. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Ancillary services" means the functions that maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event. Ancillary services include but are not limited to synchronized regulation, contingency reserves, flexibility reserves, voltage and frequency response, power factor corrections, and spinning reserves.

(b) “Capacity need” means a distribution grid capacity constraint or shortfall projected within a ten-year period.

(c) “Demand flexibility” means the ability to help utilities manage or balance load by shifting electricity use across hours of the day to reshape customer load profiles or dynamically respond to system conditions while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality and delivering net benefits to the system, customers, or society. Demand flexibility often uses distributed energy resources, communication and/or control technologies.

(d) “Demand response measures” or “demand response” or “DR” means any modulation in customer electric usage at targeted times, including reduction of usage or shifting of usage from one time to another, or interruption or curtailment of electric usage, either with load control equipment or in response to incentives, a signal, or changes in the price of electricity designed to induce changes in electricity use at specific times.

(e) “Direct current fast charger” means a high-power fast charging method of at least 50 kW capacity used to resupply an electric vehicle using direct current electricity, typically 208/480V three-phase.

(f) “Distributed energy resources” or “DER” may include, but are not limited to, distributed generation, energy storage systems, electric vehicles, microgrids, fuel cells, and demand side management measures including energy efficiency, demand response, and demand flexibility that are deployed at the distribution grid level, on either the customer or utility side of the meter. DER can be used to optimize energy use and generation to satisfy the energy, capacity, or ancillary service needs of the distribution grid.

(g) “Distribution system plan” or “DSP” means the compliance plan filed in accordance with rule 3528.

(h) “Energy efficiency measures” are measures that target consumer behavior, equipment, or devices that result in the decrease in electricity usage of customers without detriment to end-use services.

(i) “Grid availability” means the hours per year when the utility makes the grid or a portion of the grid available for use not only by load but also by distributed generation and demand response.

(j) “Grid need” means the need for energy, capacity, ancillary services, reliability, or resiliency services to address a forecasted deficiency on the electric distribution system.

(k) “Hosting capacity” means 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.

(l) “Locational value” means an analysis of distributed energy resources that incorporates location-specific incremental net benefits to the electric grid.

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

(n) “Microgrid” means a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that can act as a single controllable entity with respect to the grid. A microgrid is capable of connecting and disconnecting from the centralized grid to enable the microgrid to operate in both grid-connected or island-mode.

(o) “N-1 event” means an outage event of one distribution or transmission element such as a transformer, feeder, or transmission line that may cause load to shift to other elements as backup. An N-1 event indicates a need for additional reliability capacity if it is determined to cause a potential overload on elements carrying energy to accommodate the event.

(p) “Non-Wires Alternative” or “NWA” means the strategic deployment of distributed energy resources by a utility or a third party and associated control or aggregation of systems and technologies intended to cost-effectively defer or avoid the need for Major Distribution Grid Projects. An NWA is intended to reliably reduce load, congestion or other constraints at times of peak demand in targeted locations on the grid. NWAs can include one or multiple DER, including but not limited to demand response measures, energy efficiency, energy storage, and distributed generation. NWA projects can include these and other investments individually or in combination to meet the specified need.

(q) “Pilot” means a utility offering to test a new use or deployment of DER for a set period of time with a specified end date and number of customers, wherein the utility seeks to gain experience or expertise, and to inform the Commission.

(r) “Program” means an ongoing, long-term offering by the utility with no specified end date that utilizes or deploys DER on the distribution grid in a manner that provides system benefits or cost savings.

(s) “Ratable procurement” means the procurement of incremental DER capacity to defer or avoid long-term traditional utility infrastructure or grid needs driven by steady load growth.

(t) “Reliability need” means a risk of failure requiring mitigation due to inadequate capacity or voltage support, or an N-1 event on the distribution grid.

(u) “Resilience” is the ability of the distribution grid to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.

3528. Distribution System Plan Filing Requirements.

A utility with over 500,000 customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2022. A utility with 500,000 or fewer customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2023.

(a) Each DSP application filing shall conform to the application requirements contained in rules 3002 and rule 1303 of the Commission's Rules of Practice and Procedure.

(b) Within 30 days of the filing of the application, the Commission shall issue a decision addressing whether the contents of the DSP meet Commission standards based on the information provided by the utility set forth in paragraph 3528(d).

(c) If the DSP identifies major distribution grid projects that meet the NWA suitability screening criteria put forth in paragraph 3534(a), then the DSP proceeding shall consist of two phases.

(I) Within the same proceeding and subject to paragraph 3528(b), the utility shall file a Phase II DSP within 120 days of the filing of the Commission's order establishing the final Phase I DSP.

(A) Within 30 days after the filing of the Phase II DSP, parties may submit comments pertaining to the Phase II DSP.

(B) Within 15 days after the deadline for initial comments on the Phase II DSP, parties may submit reply comments.

(d) If the utility claims that any of the requirements set forth in rules 3529 through 3541 are not yet practicable to provide or are currently cost-prohibitive to provide, the utility shall indicate for each requirement:

(I) why the information is not yet practicable or is currently cost-prohibitive, what information could be provided in the alternative and how that alternative information would achieve planning and policy objectives;

(II) how the information could be obtained in future filings, and if so, at what estimated cost, and on what timeframe;

(III) what the benefits or limitations of filing the data in future reports would be as related to achieving the planning and policy objectives; and

(IV) if the information cannot be provided in future reports, what information could be provided in the alternative and how it would achieve planning and policy objectives.

(e) The utility shall file a final DSP action plan in accordance with rule 3536, including all required modifications, within 60 days of the Commission's final decision.

(f) The utility may file, at any time, an application to amend the contents of a DSP approved pursuant to paragraph 3536(c). Such an application shall meet the requirements of paragraphs 3002(b) and 3002(c), shall identify each proposed amendment, shall state the reason for each proposed amendment, and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

(g) Utilities are encouraged to convene regular, informal stakeholder meetings to discuss DSP-related issues and to inform the contents of DSP applications. The utility shall convene at least one stakeholder meeting at least 90 days prior to the filing of the DSP. As part of these

stakeholder meetings, the utility shall solicit input on future programs and/or pilots and solicit feedback on both the hosting capacity analysis and the web portal. The utility shall make all reasonable efforts to engage local governments and community organizations representing disproportionately impacted communities. The Commission may, at its discretion, require utilities to host stakeholder discussions regarding specific DSP topics.

3529. Contents of the Distribution System Plan.

(a) The utility shall file a Phase I DSP with the Commission that contains the information specified below. When required by the Commission, the utility shall provide any relevant studies, additional data, and work-papers to support the information contained in the plan. The DSP shall include the following:

(I) 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;

(II) a description of how the distribution grid may evolve over the next five and ten years due to various factors, such as increasing DER penetration, the expansion of beneficial electrification programs and other electrification, advanced metering infrastructure, increasing demand flexibility, energy efficiency and other emerging technologies. The utility should discuss the challenges and opportunities presented by the emergence of new technology as well as plans they have to adapt to or utilize these changes to the grid;

(III) 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;

(IV) distribution system forecasts, as described in rule 3530;

(V) an assessment of the existing distribution system, as described in rule 3531;

(VI) an assessment of grid needs, as described in rule 3532;

(VII) a description of grid innovations and any proposed pilots and programs, as described in rule 3533;

(VIII) NWA suitability screening results, as described in rule 3534;

(IX) a proposed NWA cost benefit analysis methodology, as described in rule 3535;

(X) any proposed documents and model contracts that the utility intends to use for NWA solicitation or procurement;

(XI) a Phase I action plan, as described in rule 3536;

(XII) a proposal for cost recovery, which may include an incentive, as described in rule 3538;

(XIII) a security assessment, as described in rule 3539.

(XIV) a proposal for implementation of a web portal as described in paragraph 3541(d);

(XV) a description of the stakeholder engagement process, as described in paragraph 3528(g); and

(XVI) 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.

3530. Distribution System Forecasts.

(a) Forecast requirements. The utility shall prepare demand forecasts for each year within the ten-year planning period. The utility shall also prepare ten-year forecasts for load growth on the distribution grid, including the growth of various types of DERs connected to the distribution grid. Forecasts should be based on at least two growth scenarios (State Policy and High), including 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. Forecasted growth should include the following:

(I) peak load growth at each substation, by year;

(II) peak load growth at each substation transformer by year;

(III) peak load growth on each feeder, by year;

(IV) coincident peak and non-coincident peak load growth at substations, transformers, and feeders, by voltage class;

(V) load growth associated with beneficial electrification, by substation transformer and by feeder under each scenario in subparagraph 3530(a)(X);

(VI) load growth due to new planned neighborhoods or housing developments,

(VII) net load impacts due to DER adoption under each scenario in subparagraph 3530(a)(X);

(VIII) net load impacts due to demand side management, demand response, and demand flexibility;

(IX) approved CSG capacity in RES Plans and anticipated CSG capacity additions beyond the current effective RES plans;

(X) forecasts of DERs and NWA should include ten-year scenarios that project expected growth of DERs and NWA, including expected geographic dispersion at the distribution feeder level and impacts on distribution planning. Scenarios shall be designed to meet or exceed current state policy such as those related to greenhouse gas (GHG) reductions,

increased use of DERs, electrification, distribution reliability, resiliency, and transmission system needs. Scenarios shall include key inputs including growth of peak exported generation or net generation from distributed solar generation; growth of peak exported generation or net generation from distributed battery storage systems; and growth of peak exported generation or net generation from all other distributed generation. Scenarios shall be based on the following criteria:

(A) State Policy Goal Scenario: Adopts a current forecast case for DER and NWA deployment for distribution planning at the feeder level, assuming compliance with current state policy goals.

(B) High Growth Scenario: Adopts a high growth case for DERs. This scenario should exceed state policy goals, which may include long-term GHG reductions, and beneficial electrification at levels higher or faster than required in state statute or incurrent state policy goals. Additionally, the High Growth Scenario may improve upon performance in areas of demand flexibility, distribution reliability, resiliency, and transmission system needs beyond a business as usual projection.

(b) The utility shall provide all assumptions and methodologies that are inputs into the forecasting scenarios in paragraph 3530(a).

3531. Assessment of Existing Distribution System.

(a) System overview and substation historical data.

(I) To identify and assess needs on the distribution system, each utility shall provide a map of existing and planned substations within its service territory, as well as tabular information about the current design capacity, and performance of each substation and substation transformer. The assessment should also include the status of advanced metering infrastructure deployment which may be made by reference to other reports or filings. At a minimum, this should include the following information for each substation and substation transformer on the utility's distribution grid:

(A) maximum rated capacity of each substation transformer;

(B) peak hourly demand on each substation transformer for the past three years;

(C) capacity margin for each substation transformer;

(D) advanced functionality capabilities of each substation transformer;

(E) number of feeders served by each substation and substation transformer;

(F) maximum rated capacity of each feeder;

(G) peak hourly demand on each feeder for the past three years;

(H) capacity margin for each feeder;

(I) percentage of grid availability;

(J) minimum daytime load;

(K) aggregate miles of underground and overhead wires, categorized by voltage class;

(L) monitoring capabilities and data collection on the distribution system, such as the substations and feeders for which the utility has real-time supervisory control and data acquisition (SCADA) capability;

(M) amount of distributed generation installed on the system (number of systems and nameplate capacity in kilowatts (kW) by generator types, organized by substation or feeder);

(N) description of NWA on the system, organized by substation or feeder; including annual cost savings and greenhouse gas emissions reductions;

(O) amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours (kW and kWh));

(P) estimated number of EVs and Level 2 and DCFC EV charging stations organized by substation or feeder;

(Q) estimated demand flexibility capacity on the system and historic utilization of those flexibility capabilities;

(R) voltage and power quality data for the past three years; and

(S) location of highly seasonal circuits as defined by subparagraph 3667(a)(IV).

(II) Hosting capacity analysis.

(A) As part of its DSP, each utility shall develop a hosting capacity analysis of the distribution system.

(B) The analysis shall determine the hosting capacity on a particular feeder, feeder section or substation at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

(C) The hosting capacity analysis shall be performed using a load flow analysis and forecasted distribution facilities and their capacity, configuration, loading, and voltage data gathered at the substation, feeder, and primary node levels where available.

(D) The utility shall perform scenario analysis to evaluate hosting capacity need under normal, planned contingency, and unplanned contingency conditions, for both the State Policy and High Growth scenario.

(E) The utility shall provide a detailed description of the methods and outcomes it used to perform the hosting capacity analysis.

(F) The hosting capacity analysis shall reflect that which appears in the web portal as described in rule 3541. The utility shall also provide a detailed narrative describing the utility's progress towards advancements to the accuracy and value of the hosting capacity analysis and providing real-time hosting capacity data. This should include a description of how its hosting capacity analysis currently advances customer-sited DER (in particular distributed renewable electric generation and energy storage systems), how the utility anticipates the hosting capacity analysis will aid in identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which the utility anticipates customer benefit stemming from the hosting capacity analysis.

(G) For their first DSP filing, utilities with 500,000 or fewer customers shall provide an Excel spreadsheet (or equivalent format) by feeder of either daily daytime minimum load or, if daytime minimum load is not available, daily peak load with the time granularity specified. If daytime minimum load or daily peak load data are unavailable, the utility shall explain why the data are unavailable.

3532. Grid Needs Assessment.

(a) The utility shall provide a summary analysis of the energy, capacity, ancillary services, and reliability needs and constraints on a utility's distribution system and solutions to those needs.

(b) The grid needs assessment shall include an analysis regarding the suitability of non-wires alternatives to mitigate identified needs and recommendations for the deployment of utility infrastructure upgrade solutions versus the procurement of non-wires alternative solutions to address any identified needs.

(c) The grid needs assessment shall address existing and forecasted needs over a ten-year planning period that could result in a major distribution grid project.

(d) The grid needs assessment shall include each of the following parts.

(I) An assessment of critical needs.

(A) The utility shall provide an assessment of critical capacity and reliability needs that must be addressed within the ten-year planning horizon.

(B) The assessment shall include a review of all planned, proposed and potential major distribution grid projects which will be required to address constraints related to substation transformers and feeders that are forecasted to have insufficient capacity to adequately serve peak load or reliability needs over the next ten years.

(C) The assessment shall be divided into two parts – one detailing short-term needs within zero to three years, and one detailing longer-term needs in four to ten years.

(D) The data used for the assessment shall be provided in megawatt values in tables, in a logical spreadsheet form (both printed and functional Excel spreadsheet formats) and graphically as a map in executable ARC GIS or similar format.

(E) The assessment of critical needs will be provided via the web portal, described in rule 3541. Any notable updates to the web portal should also be made in this section of the DSP.

(F) The assessment shall include a review of the capability of the distribution system and any needs incurred to interconnect approved CSG capacity in the utility's current SGIP queue. The assessment shall include an estimate of the potential benefits and costs of infrastructure upgrades. The assessment shall also include a good faith effort by the utility to assess any needs to interconnect capacity approved in its most recent RES Plan but not yet acquired, and a reasonable expectation of future CSG capacity during the DSP planning period for targeted development areas. The utility will work with stakeholders to assess the level of interest for targeted development at specific locations for future CSG capacity and the corresponding potential benefits and costs of infrastructure upgrade needs at those specific locations.

(II) The utility's current distribution plan for distribution grid investments, as well as the total capital budget including the past three years and the next five years of projected budget. Budgets shall be broken down by relevant budget categories.

(III) Fast charging locations for electric vehicles. The utility shall use the results of the grid needs assessment to identify locations where substation transformers and feeders have sufficient capacity for hosting multiple direct current fast chargers for electric vehicles. Utilities will also assess vehicle-to-grid (V2G) opportunities as potential NWA projects.

(IV) An identification of any long-term needs identified in the grid needs assessment for which ratable procurement may avoid or defer the anticipated need driven by steady load growth, including geographically targeted deployment of demand flexibility, demand response, and energy efficiency measures.

3533. Grid Innovation.

(a) The DSP shall address DSP pilots and programs that are either in progress, planned, or have been suggested by other parties and found to have merit by the utility. The DSP shall identify any barriers to deployment of DERs and NWA. Such barriers may include but not be limited to integration or interconnection of DERs and NWAs, barriers that limit the ability of a DER and NWA to provide benefits, and barriers related to distribution system operation and infrastructure capability. This section shall include, but not be limited to:

(I) Within each DSP, the utility may propose new pilots and programs designed to gain experience integrating DER, NWA or other new distribution technologies in a way that improves system performance, minimizes system costs, increases system resiliency and/or reliability, and/or reduces greenhouse gas emissions including from reduced curtailment of renewable energy. Such pilots and programs may be proposed as solutions to help solve identified grid needs identified under rule 3532.

(II) New proposed pilots. Within each DSP, the utility may propose new pilots. Pilots shall not be required to pass a cost-benefit test; however, the Commission shall determine that the pilot can be implemented at a reasonable cost and rate impact. Each of the proposed pilots shall, at a minimum, include:

(A) a description of what the utility seeks to learn through the pilot with specific goals and metrics;

(B) an explanation of how the pilot can be scaled to enable the utility to achieve objectives described in the plan pursuant to rule 3529;

(C) the specific DER and NWA technology or technologies eligible for the pilot, including any operational requirements;

(D) a description of any geographic or locational focus of the pilot;

(E) the customer classes that may participate in the pilot;

(F) a description of the potential benefits the utility expects the pilot technology to demonstrate;

(G) a description of the costs of the pilot, including a cap on costs for each pilot;

(H) criteria for evaluation of the pilot and an evaluation plan that includes a calculation of pilot costs, schedule, and a summary of pilot benefits, including quantified benefits, as available;

(I) a description of the use of any targeted incentive payments, or other incentives, provided to participants;

(J) a description of the mechanism to acquire equipment, technologies, vendors, and participants in the pilot; and

(K) a description of how the pilot will provide health, safety, environmental, or financial benefits to disproportionately impacted communities.

(III) New proposed programs. Within its DSP, the utility may seek approval for a new program to better integrate DER and NWA or other distribution technologies into its business practices in a way that improves system performance, minimizes costs, increases system resiliency and reliability, or reduces emissions. Proposed programs may be successors of completed pilots; however, a utility does not need to have conducted a pilot in order to seek approval for a new program.

(IV) The utility may propose pilots or programs developed internally and shall also accept third-party proposals for pilots and programs at any time. For a third-party pilot or program to be considered in a DSP, it must be received by the utility at least six months prior to the DSP filing deadline. 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. For any proposal not considered, the utility shall explain why it was not considered.

(V) Updates on existing pilots and programs. Within its DSP, the utility shall provide a narrative status update on all active pilots and programs approved in prior DSPs. The utility may also seek reauthorization of existing programs within a DSP. As part of its first DSP, the utility is encouraged to evaluate whether any existing reporting obligations outside the DSP related to distribution system pilots, programs, or projects should be centralized within the DSP process. Upon Commission approval, and notice filed within the original proceeding, such reporting obligations shall be transferred to DSP proceedings.

(b) NWAs and pilots may include the use of targeted incentive payments to encourage DER adoption or optimize the use of existing DERs by customers in specific locations, to provide locational value to the system. Such incentives shall be accounted for in the cost benefit analysis as described in rule 3535 and shall be recovered in a manner similar to other distribution-grid related expenditures.

3534. NWA Suitability Screening.

(a) Major distribution grid projects identified to be necessary in the grid needs assessment conducted pursuant to rule 3532 shall be subject to an NWA suitability screening to determine if a NWA may be a suitable alternative to traditional utility infrastructure solutions.

(b) The NWA suitability screening is performed by the utility and includes the following criteria:

(I) the project is anticipated to occur during the ten-year planning horizon;

(II) the constraint is due to thermal loading, voltage, capacity or reliability issues and could be resolved by a DER, a reduction in peak demand loading, a reduction in energy consumption, or load shifting on the transmission or distribution facilities; and

(III) the conventional solution is still within the planning or design stage, with no major equipment on order, received, or installed that cannot be repurposed for other uses.

(c) The utility may seek a waiver from these requirements on a case-by-case basis, if necessary, to preserve reliability, serve economic development needs, or to meet other unforeseen circumstances where the utility expects a non-wires alternative cannot adequately resolve or the planning constraint. Such requests should be substantiated to show why the NWA suitability screening is not possible or could not reasonably result in an alternative to traditional utility infrastructure. Should the utility assert that a NWA is infeasible due to the urgency of the grid need, the utility shall also explain why the grid need was not previously identified.

(d) For all major distribution grid projects identified as meeting all the NWA suitability screening, the utility shall conduct a technology-neutral competitive solicitation for NWAs to defer, reduce, or avoid the costs of the major distribution grid projects.

3535. NWA Cost Benefit Analysis.

(a) In order to assess the cost-effectiveness of a potential NWA solution that meets the NWA Suitability Screening in rule 3534, the utility shall:

(I) develop and publish a cost benefit methodology that will be provided in the utility's DSP;

(II) assess the proposed NWA solution using a cost-benefit methodology that considers the approach as put forward in the National Standard Practice Manual and specifically including the following costs and benefits: avoided or deferred costs associated with an NWA solution, sub-transmission, substation transformer additions or upgrades, feeder capital and operating costs, distribution power quality equipment, reliability and resiliency costs, energy and capacity value of generation, capacity value of storage, greenhouse gas emissions including the Commission approved social cost of carbon useful life of NWA and traditional solutions, and dispatchability and availability of the technology. If the utility is proposing a performance incentive as part of cost recovery for the NWA pursuant to paragraph 3538(d), it shall include the cost-benefit analysis both with and without the performance incentive included as a cost of the project;

(III) provide a description of DSP goals, compliance with statute, rules, and requirements, and additional relevant principles; and

(IV) assess the proposed distribution system costs, direct system benefits, indirect system benefits, and system sensitivity analysis.

(b) The utility may also propose an alternative or adjusted cost-benefit methodology if it does not believe that the full costs and benefits of the NWA solution are being counted.

3536. Action Plan.

(a) The utility shall provide a five-year action plan for distribution system investments and activities within its Phase I DSP which will serve as an application for the Commission and stakeholders to rely upon when evaluating distribution system planning projects, pilots, and programs.

(b) The Phase I action plan shall include the sequence of events and timelines for each action that will not require a solicitation process following Phase I, including:

(I) the implementation of NWAs to address grid needs not classified as major distribution system projects, and the implementation of NWAs approved in prior DSPs;

(II) the implementation of proposed pilots and programs as specified in rule 3533;

(III) the implementation of major distribution grid projects that were determined to be the best option to address grid needs;

(IV) system interoperability and communications strategy;

(V) costs and plans associated with obtaining data necessary for the evaluation of NWAs, pilots and programs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles);

(VI) interaction of planned or proposed investments with other utility programs and the effects on existing utility programs and tariffs; and

(VII) the implementation of major distribution projects intended to cost-effectively interconnect the approved and reasonably forecasted CSG capacity, including that approved by RES Plans in effect during the planning period.

(c) Subject to paragraph 3528(b), the utility shall provide an updated action plan with its Phase II DSP. This plan shall include the sequence of events and timelines for NWAs identified in the solicitation process, including:

(I) the implementation of NWAs identified through the NWA analysis process;

(II) an updated system interoperability and communications strategy;

(III) costs and plans associated with obtaining data necessary for the evaluation of NWAs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles); and

(IV) interaction of planned or proposed NWA investments with other utility programs and the effects on existing utility programs and tariffs.

3537. NWA Solicitation Process (Phase II).

(a) The utility shall propose in its DSP (Phase I) Application appropriate timelines for the release of the RFP(s), the receipt of bids, evaluation of bids, the utility's proposal to the Commission, the filing of the independent evaluator report, party comments in response to the independent evaluator report, and the Commission decision. These timelines should consider similar timelines as expressed in the Electric Resource Planning Rules, specifically rule 3613. The timelines proposed by the utility and approved by the Commission in the DSP (Phase I) shall describe an appropriately expedited, comment-based NWA Solicitation Process (Phase II) to facilitate timely decisions and implementation of NWA bids.

(b) For projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria, an Independent Evaluator (IE) shall be retained.

(I) The utility shall file for Commission approval the name of the independent evaluator. The Commission shall approve an independent evaluator by written decision during Phase I.

(II) The utility shall pay for the services provided by the independent evaluator pursuant to a contract approved by the Commission. In its Phase I DSP Application, the utility shall

specify the level and structure of any bid fees proposed to offset the independent evaluator and solicitation costs. The terms of such contract shall prohibit the independent evaluator from assisting any entity making proposals to the utility for subsequent resource acquisitions for three years.

(III) The utility shall work cooperatively with the independent evaluator and shall provide the independent evaluator immediate and continuing access to all documents and data reviewed, used, or produced by the utility in the preparation of its projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria and in its bid solicitation, evaluation, and selection processes. The utility shall make available the appropriate utility staff to meet with the independent evaluator to answer questions and, if necessary, discuss the prosecution of work. The utility shall provide to the independent evaluator, in a timely manner to facilitate the deadlines outlined in these rules, bid evaluation results and modeling runs so that the independent evaluator can verify these results and can investigate options that the utility did not consider. If the independent evaluator notes a problem or a deficiency in the bid evaluation process, the independent evaluator should notify the utility.

(IV) All parties in the DSP proceeding other than the utility are restricted from initiating contacts with the independent evaluator. The independent evaluator may initiate contact with the utility and other parties. For all contacts with parties in the DSP proceeding, including those with the utility, the independent evaluator shall maintain a log that briefly identifies the entities communicating with the independent evaluator, the date and duration of the communication, the means of communication, the topics discussed, and the materials exchanged, if any.

(V) The independent evaluator shall generally serve as an advisor to the Commission and shall generally not be a party to the proceedings. As such, the independent evaluator shall not be subject to discovery and cross-examination at hearing.

(VI) Within 30 days of a utility selecting an NWA bidder to advance to Phase II, the independent evaluator shall file a report. The independent evaluator shall address in its report whether the utility's competitive acquisition procedures and bidding policy, including the assumptions, criteria, and models, were sufficient to solicit and evaluate bids in a fair and reasonable manner, with any deficiencies specifically noted. The independent evaluator shall provide confidential versions of these reports to Commission staff and the UCA.

(c) All solicitations, unless requested by the Commission, or requested by the utility and approved by the Commission, shall be conducted in a technology neutral manner.

(d) The utility may require prospective bidders to sign non-disclosure agreements to obtain information deemed confidential or highly confidential.

(e) After final NWA bids have been selected by the utility, the utility shall update the elements of the Action Plan that pertain to NWAs.

3538. Approvals and Cost Recovery.

(a) The utility may seek Commission approval of a NWA, pilot, or program in its DSP application filing. Should such an approval be sought, the Commission may require a hearing specifically on the NWA pilot, or program in addition to the process described in rule 3536. The Commission may require the utility to demonstrate satisfactory compliance with appropriate benchmarks or performance metrics outlined in the Commission's decision approving pilots, programs or NWA or other components of the DSP. Utilities may seek approval to implement an NWA, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation. New pilots or programs should meet the standards and requirements set forth in paragraph 3533(a).

(b) A utility may seek any necessary approvals for a NWA, pilot or program in other proceedings, including, but not limited to:

(I) demand side management planning;

(II) renewable energy standard compliance planning;

(III) transportation electrification planning; or

(IV) innovative technology pilot programs or demonstrations.

(c) 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. 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 reasonable. The utility may seek approval to implement NWAs, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation.

(d) In the application for approval of a DSP, the utility shall address how it anticipates recovering costs associated with the investments put forward in its DSP in accordance with subparagraph 3529(a)(XI).

(I) Investments made to implement an approved DSP shall be deemed to made in the ordinary course of business and shall be recovered through the normal implementation of the utilities rate mechanisms.

(II) The utility shall demonstrate that the investments made to implement an approved DSP do not undermine equitable access to other utility programs and do not materially impact the related utility program's targeted performance.

(III) The utility may propose a performance incentive for implementing any NWA, pilot, or program as a component of its cost recovery proposal. The performance mechanism, if proposed, shall also be included as part of the cost-benefit analysis specified in rule 3535. A performance incentive may include allocating to the utility a share of the cost-savings derived from NWA implementation as compared to the avoided capital investment.

(IV) For costs the Commission deems to be incurred outside the ordinary course of business, the utility may seek approval of a regulatory asset for recovery as part of the utility's next rate case or may be placed in another cost recovery mechanism as proposed by the utility. The Commission shall establish the authorized rate of return on any regulatory asset created pursuant to this paragraph.

(e) 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.

(f) The utility shall file a final DSP, which may include required modifications, within 60 days of the Commission's final decision.

3539. Security Assessment.

(a) The utility shall provide a narrative assessment of the reliability and resilience of the distribution grid with respect to cybersecurity and physical security, including:

(I) current status of distribution grid reliability and plans for improving reliability, including areas of the grid where reliability problems have been identified, with plans for resolving them. Distribution grid reliability metrics (SAIDI and SAIFI at a minimum) should be provided for each year for the past three years for each substation;

(II) list of major outages, including cause and duration, involving 10,000 customers or more for each year for the past three years;

(III) analysis of cyber security issues or other threats to the distribution system and what efforts the utility is taking to ensure the distribution system is secure;

(IV) analysis of risks by substation posed by natural disasters such as wildfires, floods, severe storms, and a detailed description of efforts the utility is taking to increase system resiliency in the response to these risks;

(V) other plans aimed at improving distribution system resiliency; and

(VI) any pilots or programs, existing or proposed, aimed at increasing reliability and resiliency, using microgrids or other technology, should be discussed within the Grid Innovation section of the Phase I DSP, as described in rule 3533.

(VII) The utility may incorporate by reference any other filings or applications made to the Commission that are relevant to a discussion of distribution system reliability and resilience.

3540. Data Access, Privacy and Confidentiality.

(a) The utility shall disclose data necessary to implement these rules with appropriate levels of protection, considering sensitivity and public benefit. The utility shall identify and address the

treatment of sensitive information in consideration of the objectives of DSP and as required by these rules.

(b) The utility shall not disclose personal information, as defined in paragraph 1004(x), or customer data, as defined in paragraph 3001(i). Paragraph 3033(b) shall not apply to data releases under this rule.

(c) In each DSP application filing made pursuant to rule 3529, the utility shall file a list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information that the utility claims is highly confidential, and its proposed treatment of the information. For good cause shown, the utility may seek to protect information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

3541. Web Portal.

(a) The utility shall make available a web portal that provide map-based and tabular data that is publicly available or access-restricted as further defined under this rule. Such web portal shall be designed to meet the objectives of the DSP and shall allow users to download data in tabular and geospatial formats

(b) The utility may only deny access to its web portal if visitors and/or registrants violate the terms of service or other agreed upon terms of access. To ensure the appropriate level of protection of sensitive information, the utility may require visitors to the web portal to take actions, including:

(I) requiring visitors to acknowledge terms of service associated with its use, provided those terms do not preclude academic or public policy purposes; and

(II) establishing registration processes, including the creation of a username and password, and/or the use of multifactor authentication for access to sensitive information.

(c) A web portal shall include at least the following information:

(I) consistent with subparagraph 3531(a)(II), the utility's hosting capacity analysis;

(II) publicly available summaries, data, or links to existing information on the utility's website related to programs approved by the Commission that address the deployment of DERs, including, without limitation, pilots, tariffs, and incentives; and

(III) any additional content as directed by the Commission.

(d) Implementation of the web portal.

(I) Prior to filing its first DSP application pursuant to rule 3529, the utility shall engage potential users of the web portal from multiple sectors to develop a proposal for implementation of the web portal to be filed with the application.

(II) In its first DSP application pursuant to rule 3529, the utility shall present a proposal and timeline for developing a web portal that meets the requirements of this rule and includes:

(A) a summary of its process for identifying and engaging potential users of the web portal and the results of that process;

(B) a description of use cases that will be implemented through the web portal to meet the objectives of DSP;

(C) an evaluation of the data required in a DSP application pursuant to rule 3529 that addresses what data will be provided on the web portal and at what level of granularity, an evaluation of the risks and benefits associated with providing such data, proposals for treatment of sensitive information, and identifying any data for which confidential or highly confidential treatment is sought under the process provided in paragraph 3540(c);

(D) a proposal for providing functionalities that enhance the user experience, such as color-coding of substations, circuits, and feeders or ability to change the year of the data being displayed;

(E) a proposal for what information is currently available and can be provided on a web portal and what information requires approval by the Commission for incorporation onto a web portal;

(F) a proposal for updating data provided through the web portal, specifically addressing the quarterly updating of the utility's hosting capacity analysis as described in subparagraph 3531(a)(II);

(G) a proposal for enabling Application Programming Interface (API) capabilities where reasonable and appropriate; and

(H) a proposal for collecting user feedback on an ongoing basis.

(III) In subsequent DSP application proceedings, the utility shall provide an update on the status of implementing the web portal and any proposed changes to functionality and treatment of data. Prior to each application pursuant to rule 3529, the utility is encouraged to engage with stakeholders including users of the web portal, to identify changes.

(IV) The utility shall file an annual compliance report in the most recent DSP application proceeding that provides an update on the status of implementing the web portal, summarizes user feedback, and describes how the utility addressed that feedback, including any updates or revisions to the functionality of the web portal that are anticipated to occur prior to its next DSP application filing.

3542. Evaluation and Reporting.

(a) An assessment of the existing distribution system, as described in rule 3531.

(b) An assessment of Distribution Grid Security, as described in rule 3539.

(c) Starting with its second DSP application, the utility shall describe the 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.

(d) The utility shall report lessons learned from the DSP process and identify ways to improve methodologies through research before the next filing.

(e) Should the utility receive approval for an NWA, a DSP related pilot, or a DSP-related program in a proceeding other than a DSP application, for active projects the utility shall provide in subsequent DSPs:

(I) the name of the project;

(II) a brief description of the project;

(III) the number of the proceeding in which the utility is seeking or has received approval for the project;

(IV) the number(s) of any other proceedings that contain reporting for the project;

(V) the date of project approval, if applicable;

(VI) the total proposed or approved budget; and

(VII) a description of the proposed or approved budget by funding source.

3543. – 3549. [Reserved].

COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-3

PART 3
RULES REGULATING ELECTRIC UTILITIES

3506. – 3524. [Reserved].

DISTRIBUTION SYSTEM PLANNING

3525. Applicability

This rule shall apply to all electric utilities in the state of Colorado that own distribution facilities except municipally owned electric utilities and cooperative electric associations that have voted to exempt themselves from the Public Utilities Law pursuant to § 40-9.5-104, C.R.S.

3526. Overview and Purpose.

The purpose of these rules, as directed by § 40-2-132, C.R.S., is to require electric utilities to file a Distribution System Plan (DSP) that enables the Commission to review and evaluate the utility's investments in the distribution grid to ensure that they cost-effectively support grid adequacy, reliability and resilience and prepare for new expectations upon the distribution system, while simultaneously ensuring progress toward priorities highlighted by state legislation, including but not limited to supporting diversification of energy supply through distributed energy resources, expanding the utilization of non-wire alternatives that may reduce the need for conventional distribution grid investment, reducing greenhouse gas emissions, advancing building and transportation electrification, maintaining affordable customer rates, and promoting equity with regard to disproportionately impacted communities. These rules should also establish a proactive and transparent process for enhancing understanding of key distribution system characteristics.

3527. Definitions.

The following definitions apply to rules 3525 through 3542. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Ancillary services" means the functions that maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event. Ancillary services include but are not limited to synchronized regulation, contingency reserves, flexibility reserves, voltage and frequency response, power factor corrections, and spinning reserves.

(b) “Capacity need” means a distribution grid capacity constraint or shortfall projected within a ten-year period.

(c) “Demand flexibility” means the ability to help utilities manage or balance load by shifting electricity use across hours of the day to reshape customer load profiles or dynamically respond to system conditions while delivering end-use services (e.g., air conditioning, domestic hot water, electric vehicle charging) at the same or better quality and delivering net benefits to the system, customers, or society. Demand flexibility often uses distributed energy resources, communication and/or control technologies.

(d) “Demand response measures” or “demand response” or “DR” means any modulation in customer electric usage at targeted times, including reduction of usage or shifting of usage from one time to another, or interruption or curtailment of electric usage, either with load control equipment or in response to incentives, a signal, or changes in the price of electricity designed to induce changes in electricity use at specific times.

(e) “Direct current fast charger” means a high-power fast charging method of at least 50 kW capacity used to resupply an electric vehicle using direct current electricity, typically 208/480V three-phase.

(f) “Distributed energy resources” or “DER” may include, but are not limited to, distributed generation, energy storage systems, electric vehicles, microgrids, fuel cells, and demand side management measures including energy efficiency, demand response, and demand flexibility that are deployed at the distribution grid level, on either the customer or utility side of the meter. DER can be used to optimize energy use and generation to satisfy the energy, capacity, or ancillary service needs of the distribution grid.

(g) “Distribution system plan” or “DSP” means the compliance plan filed in accordance with rule 3528.

(h) “Energy efficiency measures” are measures that target consumer behavior, equipment, or devices that result in the decrease in electricity usage of customers without detriment to end-use services.

(i) “Grid availability” means the hours per year when the utility makes the grid or a portion of the grid available for use not only by load but also by distributed generation and demand response.

(j) “Grid need” means the need for energy, capacity, ancillary services, reliability, or resiliency services to address a forecasted deficiency on the electric distribution system.

(k) “Hosting capacity” means 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.

(l) “Locational value” means an analysis of distributed energy resources that incorporates location-specific incremental net benefits to the electric grid.

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

(n) "Microgrid" means a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that can act as a single controllable entity with respect to the grid. A microgrid is capable of connecting and disconnecting from the centralized grid to enable the microgrid to operate in both grid-connected or island-mode.

(o) "N-1 event" means an outage event of one distribution or transmission element such as a transformer, feeder, or transmission line that may cause load to shift to other elements as backup. An N-1 event indicates a need for additional reliability capacity if it is determined to cause a potential overload on elements carrying energy to accommodate the event.

(p) "Non-Wires Alternative" or "NWA" means the strategic deployment of distributed energy resources by a utility or a third party and associated control or aggregation of systems and technologies intended to cost-effectively defer or avoid the need for Major Distribution Grid Projects. An NWA is intended to reliably reduce load, congestion or other constraints at times of peak demand in targeted locations on the grid. NWAs can include one or multiple DER, including but not limited to demand response measures, energy efficiency, energy storage, and distributed generation. NWA projects can include these and other investments individually or in combination to meet the specified need.

(q) "Pilot" means a utility offering to test a new use or deployment of DER for a set period of time with a specified end date and number of customers, wherein the utility seeks to gain experience or expertise, and to inform the Commission.

(r) "Program" means an ongoing, long-term offering by the utility with no specified end date that utilizes or deploys DER on the distribution grid in a manner that provides system benefits or cost savings.

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

(t) "Reliability need" means a risk of failure requiring mitigation due to inadequate capacity or voltage support, or an N-1 event on the distribution grid.

(u) "Resilience" is the ability of the distribution grid to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.

3528. Distribution System Plan Filing Requirements.

A utility with over 500,000 customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2022. A utility with 500,000 or fewer customers shall file a DSP as an application, every two years, with the first DSP to be submitted on or before January 31, 2023.

(a) Each DSP application filing shall conform to the application requirements contained in rules 3002 and rule 1303 of the Commission's Rules of Practice and Procedure.

(b) Within 30 days of the filing of the application, the Commission shall issue a decision addressing whether the contents of the DSP meet Commission standards based on the information provided by the utility set forth in paragraph 3528(d).

(c) If the DSP identifies major distribution grid projects that meet the NWA suitability screening criteria put forth in paragraph 3534(a), then the DSP proceeding shall consist of two phases.

(I) Within the same proceeding and subject to paragraph 3528(b), the utility shall file a Phase II DSP within 120 days of the filing of the Commission's order establishing the final Phase I DSP.

(A) Within 30 days after the filing of the Phase II DSP, parties may submit comments pertaining to the Phase II DSP.

(B) Within 15 days after the deadline for initial comments on the Phase II DSP, parties may submit reply comments.

(d) If the utility claims that any of the requirements set forth in rules 3529 through 3541 are not yet practicable to provide or are currently cost-prohibitive to provide, the utility shall indicate for each requirement:

(I) why the information is not yet practicable or is currently cost-prohibitive, what information could be provided in the alternative and how that alternative information would achieve planning and policy objectives;

(II) how the information could be obtained in future filings, and if so, at what estimated cost, and on what timeframe;

(III) what the benefits or limitations of filing the data in future reports would be as related to achieving the planning and policy objectives; and

(IV) if the information cannot be provided in future reports, what information could be provided in the alternative and how it would achieve planning and policy objectives.

(e) The utility shall file a final DSP action plan in accordance with rule 3536, including all required modifications, within 60 days of the Commission's final decision.

(f) The utility may file, at any time, an application to amend the contents of a DSP approved pursuant to paragraph 3536(c). Such an application shall meet the requirements of paragraphs 3002(b) and 3002(c), shall identify each proposed amendment, shall state the reason for each proposed amendment, and shall be administered pursuant to the Commission's Rules Regulating Practice and Procedure.

(g) Utilities are encouraged to convene regular, informal stakeholder meetings to discuss DSP-related issues and to inform the contents of DSP applications. The utility shall convene at least one stakeholder meeting at least 90 days prior to the filing of the DSP. As part of these

stakeholder meetings, the utility shall solicit input on future programs and/or pilots and solicit feedback on both the hosting capacity analysis and the web portal. The utility shall make all reasonable efforts to engage local governments and community organizations representing disproportionately impacted communities. The Commission may, at its discretion, require utilities to host stakeholder discussions regarding specific DSP topics.

3529. Contents of the Distribution System Plan.

(a) The utility shall file a Phase I DSP with the Commission that contains the information specified below. When required by the Commission, the utility shall provide any relevant studies, additional data, and work-papers to support the information contained in the plan. The DSP shall include the following:

(I) 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;

(II) a description of how the distribution grid may evolve over the next five and ten years due to various factors, such as increasing DER penetration, the expansion of beneficial electrification programs and other electrification, advanced metering infrastructure, increasing demand flexibility, energy efficiency and other emerging technologies. The utility should discuss the challenges and opportunities presented by the emergence of new technology as well as plans they have to adapt to or utilize these changes to the grid;

(III) 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;

(IV) distribution system forecasts, as described in rule 3530;

(V) an assessment of the existing distribution system, as described in rule 3531;

(VI) an assessment of grid needs, as described in rule 3532;

(VII) a description of grid innovations and any proposed pilots and programs, as described in rule 3533;

(VIII) NWA suitability screening results, as described in rule 3534;

(IX) a proposed NWA cost benefit analysis methodology, as described in rule 3535;

(X) any proposed documents and model contracts that the utility intends to use for NWA solicitation or procurement;

(XI) a Phase I action plan, as described in rule 3536;

(XII) a proposal for cost recovery, which may include an incentive, as described in rule 3538;

(XIII) a security assessment, as described in rule 3539.

(XIV) a proposal for implementation of a web portal as described in paragraph 3541(d);

(XV) a description of the stakeholder engagement process, as described in paragraph 3528(g); and

(XVI) 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.

3530. Distribution System Forecasts.

(a) Forecast requirements. The utility shall prepare demand forecasts for each year within the ten-year planning period. The utility shall also prepare ten-year forecasts for load growth on the distribution grid, including the growth of various types of DERs connected to the distribution grid. Forecasts should be based on at least two growth scenarios (State Policy and High), including 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. Forecasted growth should include the following:

(I) peak load growth at each substation, by year;

(II) peak load growth at each substation transformer by year;

(III) peak load growth on each feeder, by year;

(IV) coincident peak and non-coincident peak load growth at substations, transformers, and feeders, by voltage class;

(V) load growth associated with beneficial electrification, by substation transformer and by feeder under each scenario in subparagraph 3530(a)(X);

(VI) load growth due to new planned neighborhoods or housing developments,

(VII) net load impacts due to DER adoption under each scenario in subparagraph 3530(a)(X);

(VIII) net load impacts due to demand side management, demand response, and demand flexibility;

(IX) approved CSG capacity in RES Plans and anticipated CSG capacity additions beyond the current effective RES plans;

(X) forecasts of DERs and NWA should include ten-year scenarios that project expected growth of DERs and NWA, including expected geographic dispersion at the distribution feeder level and impacts on distribution planning. Scenarios shall be designed to meet or exceed current state policy such as those related to greenhouse gas (GHG) reductions,

increased use of DERs, electrification, distribution reliability, resiliency, and transmission system needs. Scenarios shall include key inputs including growth of peak exported generation or net generation from distributed solar generation; growth of peak exported generation or net generation from distributed battery storage systems; and growth of peak exported generation or net generation from all other distributed generation. Scenarios shall be based on the following criteria:

(A) State Policy Goal Scenario: Adopts a current forecast case for DER and NWA deployment for distribution planning at the feeder level, assuming compliance with current state policy goals.

(B) High Growth Scenario: Adopts a high growth case for DERs. This scenario should exceed state policy goals, which may include long-term GHG reductions, and beneficial electrification at levels higher or faster than required in state statute or incurrent state policy goals. Additionally, the High Growth Scenario may improve upon performance in areas of demand flexibility, distribution reliability, resiliency, and transmission system needs beyond a business as usual projection.

(b) The utility shall provide all assumptions and methodologies that are inputs into the forecasting scenarios in paragraph 3530(a).

3531. Assessment of Existing Distribution System.

(a) System overview and substation historical data.

(I) To identify and assess needs on the distribution system, each utility shall provide a map of existing and planned substations within its service territory, as well as tabular information about the current design capacity, and performance of each substation and substation transformer. The assessment should also include the status of advanced metering infrastructure deployment which may be made by reference to other reports or filings. At a minimum, this should include the following information for each substation and substation transformer on the utility's distribution grid:

(A) maximum rated capacity of each substation transformer;

(B) peak hourly demand on each substation transformer for the past three years;

(C) capacity margin for each substation transformer;

(D) advanced functionality capabilities of each substation transformer;

(E) number of feeders served by each substation and substation transformer;

(F) maximum rated capacity of each feeder;

(G) peak hourly demand on each feeder for the past three years;

(H) capacity margin for each feeder;

(I) percentage of grid availability;

(J) minimum daytime load;

(K) aggregate miles of underground and overhead wires, categorized by voltage class;

(L) monitoring capabilities and data collection on the distribution system, such as the substations and feeders for which the utility has real-time supervisory control and data acquisition (SCADA) capability;

(M) amount of distributed generation installed on the system (number of systems and nameplate capacity in kilowatts (kW) by generator types, organized by substation or feeder);

(N) description of NWA on the system, organized by substation or feeder; including annual cost savings and greenhouse gas emissions reductions;

(O) amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours (kW and kWh));

(P) estimated number of EVs and Level 2 and DCFC EV charging stations organized by substation or feeder;

(Q) estimated demand flexibility capacity on the system and historic utilization of those flexibility capabilities;

(R) voltage and power quality data for the past three years; and

(S) location of highly seasonal circuits as defined by subparagraph 3667(a)(IV).

(II) Hosting capacity analysis.

(A) As part of its DSP, each utility shall develop a hosting capacity analysis of the distribution system.

(B) The analysis shall determine the hosting capacity on a particular feeder, feeder section or substation at a given time under existing and forecasted grid conditions and operations without adversely impacting safety, power quality, reliability, or other operational criteria.

(C) The hosting capacity analysis shall be performed using a load flow analysis and forecasted distribution facilities and their capacity, configuration, loading, and voltage data gathered at the substation, feeder, and primary node levels where available.

(D) The utility shall perform scenario analysis to evaluate hosting capacity need under normal, planned contingency, and unplanned contingency conditions, for both the State Policy and High Growth scenario.

(E) The utility shall provide a detailed description of the methods and outcomes it used to perform the hosting capacity analysis.

(F) The hosting capacity analysis shall reflect that which appears in the web portal as described in rule 3541. The utility shall also provide a detailed narrative describing the utility's progress towards advancements to the accuracy and value of the hosting capacity analysis and providing real-time hosting capacity data. This should include a description of how its hosting capacity analysis currently advances customer-sited DER (in particular distributed renewable electric generation and energy storage systems), how the utility anticipates the hosting capacity analysis will aid in identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which the utility anticipates customer benefit stemming from the hosting capacity analysis.

(G) For their first DSP filing, utilities with 500,000 or fewer customers shall provide an Excel spreadsheet (or equivalent format) by feeder of either daily daytime minimum load or, if daytime minimum load is not available, daily peak load with the time granularity specified. If daytime minimum load or daily peak load data are unavailable, the utility shall explain why the data are unavailable.

3532. Grid Needs Assessment.

(a) The utility shall provide a summary analysis of the energy, capacity, ancillary services, and reliability needs and constraints on a utility's distribution system and solutions to those needs.

(b) The grid needs assessment shall include an analysis regarding the suitability of non-wires alternatives to mitigate identified needs and recommendations for the deployment of utility infrastructure upgrade solutions versus the procurement of non-wires alternative solutions to address any identified needs.

(c) The grid needs assessment shall address existing and forecasted needs over a ten-year planning period that could result in a major distribution grid project.

(d) The grid needs assessment shall include each of the following parts.

(I) An assessment of critical needs.

(A) The utility shall provide an assessment of critical capacity and reliability needs that must be addressed within the ten-year planning horizon.

(B) The assessment shall include a review of all planned, proposed and potential major distribution grid projects which will be required to address constraints related to substation transformers and feeders that are forecasted to have insufficient capacity to adequately serve peak load or reliability needs over the next ten years.

(C) The assessment shall be divided into two parts – one detailing short-term needs within zero to three years, and one detailing longer-term needs in four to ten years.

(D) The data used for the assessment shall be provided in megawatt values in tables, in a logical spreadsheet form (both printed and functional Excel spreadsheet formats) and graphically as a map in executable ARC GIS or similar format.

(E) The assessment of critical needs will be provided via the web portal, described in rule 3541. Any notable updates to the web portal should also be made in this section of the DSP.

(F) The assessment shall include a review of the capability of the distribution system and any needs incurred to interconnect approved CSG capacity in the utility's current SGIP queue. The assessment shall include an estimate of the potential benefits and costs of infrastructure upgrades. The assessment shall also include a good faith effort by the utility to assess any needs to interconnect capacity approved in its most recent RES Plan but not yet acquired, and a reasonable expectation of future CSG capacity during the DSP planning period for targeted development areas. The utility will work with stakeholders to assess the level of interest for targeted development at specific locations for future CSG capacity and the corresponding potential benefits and costs of infrastructure upgrade needs at those specific locations.

(II) The utility's current distribution plan for distribution grid investments, as well as the total capital budget including the past three years and the next five years of projected budget. Budgets shall be broken down by relevant budget categories.

(III) Fast charging locations for electric vehicles. The utility shall use the results of the grid needs assessment to identify locations where substation transformers and feeders have sufficient capacity for hosting multiple direct current fast chargers for electric vehicles. Utilities will also assess vehicle-to-grid (V2G) opportunities as potential NWA projects.

(IV) An identification of any long-term needs identified in the grid needs assessment for which ratable procurement may avoid or defer the anticipated need driven by steady load growth, including geographically targeted deployment of demand flexibility, demand response, and energy efficiency measures.

3533. Grid Innovation.

(a) The DSP shall address DSP pilots and programs that are either in progress, planned, or have been suggested by other parties and found to have merit by the utility. The DSP shall identify any barriers to deployment of DERs and NWA. Such barriers may include but not be limited to integration or interconnection of DERs and NWAs, barriers that limit the ability of a DER and NWA to provide benefits, and barriers related to distribution system operation and infrastructure capability. This section shall include, but not be limited to:

(I) Within each DSP, the utility may propose new pilots and programs designed to gain experience integrating DER, NWA or other new distribution technologies in a way that improves system performance, minimizes system costs, increases system resiliency and/or reliability, and/or reduces greenhouse gas emissions including from reduced curtailment of renewable energy. Such pilots and programs may be proposed as solutions to help solve identified grid needs identified under rule 3532.

(II) New proposed pilots. Within each DSP, the utility may propose new pilots. Pilots shall not be required to pass a cost-benefit test; however, the Commission shall determine that the pilot can be implemented at a reasonable cost and rate impact. Each of the proposed pilots shall, at a minimum, include:

(A) a description of what the utility seeks to learn through the pilot with specific goals and metrics;

(B) an explanation of how the pilot can be scaled to enable the utility to achieve objectives described in the plan pursuant to rule 3529;

(C) the specific DER and NWA technology or technologies eligible for the pilot, including any operational requirements;

(D) a description of any geographic or locational focus of the pilot;

(E) the customer classes that may participate in the pilot;

(F) a description of the potential benefits the utility expects the pilot technology to demonstrate;

(G) a description of the costs of the pilot, including a cap on costs for each pilot;

(H) criteria for evaluation of the pilot and an evaluation plan that includes a calculation of pilot costs, schedule, and a summary of pilot benefits, including quantified benefits, as available;

(I) a description of the use of any targeted incentive payments, or other incentives, provided to participants;

(J) a description of the mechanism to acquire equipment, technologies, vendors, and participants in the pilot; and

(K) a description of how the pilot will provide health, safety, environmental, or financial benefits to disproportionately impacted communities.

(III) New proposed programs. Within its DSP, the utility may seek approval for a new program to better integrate DER and NWA or other distribution technologies into its business practices in a way that improves system performance, minimizes costs, increases system resiliency and reliability, or reduces emissions. Proposed programs may be successors of completed pilots; however, a utility does not need to have conducted a pilot in order to seek approval for a new program.

(IV) The utility may propose pilots or programs developed internally and shall also accept third-party proposals for pilots and programs at any time. For a third-party pilot or program to be considered in a DSP, it must be received by the utility at least six months prior to the DSP filing deadline. 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. For any proposal not considered, the utility shall explain why it was not considered.

(V) Updates on existing pilots and programs. Within its DSP, the utility shall provide a narrative status update on all active pilots and programs approved in prior DSPs. The utility may also seek reauthorization of existing programs within a DSP. As part of its first DSP, the utility is encouraged to evaluate whether any existing reporting obligations outside the DSP related to distribution system pilots, programs, or projects should be centralized within the DSP process. Upon Commission approval, and notice filed within the original proceeding, such reporting obligations shall be transferred to DSP proceedings.

(b) NWAs and pilots may include the use of targeted incentive payments to encourage DER adoption or optimize the use of existing DERs by customers in specific locations, to provide locational value to the system. Such incentives shall be accounted for in the cost benefit analysis as described in rule 3535 and shall be recovered in a manner similar to other distribution-grid related expenditures.

3534. NWA Suitability Screening.

(a) Major distribution grid projects identified to be necessary in the grid needs assessment conducted pursuant to rule 3532 shall be subject to an NWA suitability screening to determine if a NWA may be a suitable alternative to traditional utility infrastructure solutions.

(b) The NWA suitability screening is performed by the utility and includes the following criteria:

(I) the project is anticipated to occur during the ten-year planning horizon;

(II) the constraint is due to thermal loading, voltage, capacity or reliability issues and could be resolved by a DER, a reduction in peak demand loading, a reduction in energy consumption, or load shifting on the transmission or distribution facilities; and

(III) the conventional solution is still within the planning or design stage, with no major equipment on order, received, or installed that cannot be repurposed for other uses.

(c) The utility may seek a waiver from these requirements on a case-by-case basis, if necessary, to preserve reliability, serve economic development needs, or to meet other unforeseen circumstances where the utility expects a non-wires alternative cannot adequately resolve or the planning constraint. Such requests should be substantiated to show why the NWA suitability screening is not possible or could not reasonably result in an alternative to traditional utility infrastructure. Should the utility assert that a NWA is infeasible due to the urgency of the grid need, the utility shall also explain why the grid need was not previously identified.

(d) For all major distribution grid projects identified as meeting all the NWA suitability screening, the utility shall conduct a technology-neutral competitive solicitation for NWAs to defer, reduce, or avoid the costs of the major distribution grid projects.

3535. NWA Cost Benefit Analysis.

(a) In order to assess the cost-effectiveness of a potential NWA solution that meets the NWA Suitability Screening in rule 3534, the utility shall:

(I) develop and publish a cost benefit methodology that will be provided in the utility's DSP;

(II) assess the proposed NWA solution using a cost-benefit methodology that considers the approach as put forward in the National Standard Practice Manual and specifically including the following costs and benefits: avoided or deferred costs associated with an NWA solution, sub-transmission, substation transformer additions or upgrades, feeder capital and operating costs, distribution power quality equipment, reliability and resiliency costs, energy and capacity value of generation, capacity value of storage, greenhouse gas emissions including the Commission approved social cost of carbon useful life of NWA and traditional solutions, and dispatchability and availability of the technology. If the utility is proposing a performance incentive as part of cost recovery for the NWA pursuant to paragraph 3538(d), it shall include the cost-benefit analysis both with and without the performance incentive included as a cost of the project;

(III) provide a description of DSP goals, compliance with statute, rules, and requirements, and additional relevant principles; and

(IV) assess the proposed distribution system costs, direct system benefits, indirect system benefits, and system sensitivity analysis.

(b) The utility may also propose an alternative or adjusted cost-benefit methodology if it does not believe that the full costs and benefits of the NWA solution are being counted.

3536. Action Plan.

(a) The utility shall provide a five-year action plan for distribution system investments and activities within its Phase I DSP which will serve as an application for the Commission and stakeholders to rely upon when evaluating distribution system planning projects, pilots, and programs.

(b) The Phase I action plan shall include the sequence of events and timelines for each action that will not require a solicitation process following Phase I, including:

(I) the implementation of NWAs to address grid needs not classified as major distribution system projects, and the implementation of NWAs approved in prior DSPs;

(II) the implementation of proposed pilots and programs as specified in rule 3533;

(III) the implementation of major distribution grid projects that were determined to be the best option to address grid needs;

(IV) system interoperability and communications strategy;

(V) costs and plans associated with obtaining data necessary for the evaluation of NWAs, pilots and programs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles);

(VI) interaction of planned or proposed investments with other utility programs and the effects on existing utility programs and tariffs; and

(VII) the implementation of major distribution projects intended to cost-effectively interconnect the approved and reasonably forecasted CSG capacity, including that approved by RES Plans in effect during the planning period.

(c) Subject to paragraph 3528(b), the utility shall provide an updated action plan with its Phase II DSP. This plan shall include the sequence of events and timelines for NWAs identified in the solicitation process, including:

(I) the implementation of NWAs identified through the NWA analysis process;

(II) an updated system interoperability and communications strategy;

(III) costs and plans associated with obtaining data necessary for the evaluation of NWAs (for example, energy efficiency load shapes, solar output profiles with and without battery storage, capacity impacts of DR combined with energy efficiency, electric vehicle charging profiles); and

(IV) interaction of planned or proposed NWA investments with other utility programs and the effects on existing utility programs and tariffs.

3537. NWA Solicitation Process (Phase II).

(a) The utility shall propose in its DSP (Phase I) Application appropriate timelines for the release of the RFP(s), the receipt of bids, evaluation of bids, the utility's proposal to the Commission, the filing of the independent evaluator report, party comments in response to the independent evaluator report, and the Commission decision. These timelines should consider similar timelines as expressed in the Electric Resource Planning Rules, specifically rule 3613. The timelines proposed by the utility and approved by the Commission in the DSP (Phase I) shall describe an appropriately expedited, comment-based NWA Solicitation Process (Phase II) to facilitate timely decisions and implementation of NWA bids.

(b) For projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria, an Independent Evaluator (IE) shall be retained.

(I) The utility shall file for Commission approval the name of the independent evaluator. The Commission shall approve an independent evaluator by written decision during Phase I.

(II) The utility shall pay for the services provided by the independent evaluator pursuant to a contract approved by the Commission. In its Phase I DSP Application, the utility shall

specify the level and structure of any bid fees proposed to offset the independent evaluator and solicitation costs. The terms of such contract shall prohibit the independent evaluator from assisting any entity making proposals to the utility for subsequent resource acquisitions for three years.

(III) The utility shall work cooperatively with the independent evaluator and shall provide the independent evaluator immediate and continuing access to all documents and data reviewed, used, or produced by the utility in the preparation of its projects which meet the Major Distribution or Major Transmission grid threshold and NWA suitability screening criteria and in its bid solicitation, evaluation, and selection processes. The utility shall make available the appropriate utility staff to meet with the independent evaluator to answer questions and, if necessary, discuss the prosecution of work. The utility shall provide to the independent evaluator, in a timely manner to facilitate the deadlines outlined in these rules, bid evaluation results and modeling runs so that the independent evaluator can verify these results and can investigate options that the utility did not consider. If the independent evaluator notes a problem or a deficiency in the bid evaluation process, the independent evaluator should notify the utility.

(IV) All parties in the DSP proceeding other than the utility are restricted from initiating contacts with the independent evaluator. The independent evaluator may initiate contact with the utility and other parties. For all contacts with parties in the DSP proceeding, including those with the utility, the independent evaluator shall maintain a log that briefly identifies the entities communicating with the independent evaluator, the date and duration of the communication, the means of communication, the topics discussed, and the materials exchanged, if any.

(V) The independent evaluator shall generally serve as an advisor to the Commission and shall generally not be a party to the proceedings. As such, the independent evaluator shall not be subject to discovery and cross-examination at hearing.

(VI) Within 30 days of a utility selecting an NWA bidder to advance to Phase II, the independent evaluator shall file a report. The independent evaluator shall address in its report whether the utility's competitive acquisition procedures and bidding policy, including the assumptions, criteria, and models, were sufficient to solicit and evaluate bids in a fair and reasonable manner, with any deficiencies specifically noted. The independent evaluator shall provide confidential versions of these reports to Commission staff and the UCA.

(c) All solicitations, unless requested by the Commission, or requested by the utility and approved by the Commission, shall be conducted in a technology neutral manner.

(d) The utility may require prospective bidders to sign non-disclosure agreements to obtain information deemed confidential or highly confidential.

(e) After final NWA bids have been selected by the utility, the utility shall update the elements of the Action Plan that pertain to NWAs.

3538. Approvals and Cost Recovery.

(a) The utility may seek Commission approval of a NWA, pilot, or program in its DSP application filing. Should such an approval be sought, the Commission may require a hearing specifically on the NWA pilot, or program in addition to the process described in rule 3536. The Commission may require the utility to demonstrate satisfactory compliance with appropriate benchmarks or performance metrics outlined in the Commission's decision approving pilots, programs or NWA or other components of the DSP. Utilities may seek approval to implement an NWA, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation. New pilots or programs should meet the standards and requirements set forth in paragraph 3533(a).

(b) A utility may seek any necessary approvals for a NWA, pilot or program in other proceedings, including, but not limited to:

(I) demand side management planning;

(II) renewable energy standard compliance planning;

(III) transportation electrification planning; or

(IV) innovative technology pilot programs or demonstrations.

(c) 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. 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 reasonable. The utility may seek approval to implement NWAs, pilot, or program not classified as major distribution grid projects without performing a competitive solicitation.

(d) In the application for approval of a DSP, the utility shall address how it anticipates recovering costs associated with the investments put forward in its DSP in accordance with subparagraph 3529(a)(XI).

(I) Investments made to implement an approved DSP shall be deemed to made in the ordinary course of business and shall be recovered through the normal implementation of the utilities rate mechanisms.

(II) The utility shall demonstrate that the investments made to implement an approved DSP do not undermine equitable access to other utility programs and do not materially impact the related utility program's targeted performance.

(III) The utility may propose a performance incentive for implementing any NWA, pilot, or program as a component of its cost recovery proposal. The performance mechanism, if proposed, shall also be included as part of the cost-benefit analysis specified in rule 3535. A performance incentive may include allocating to the utility a share of the cost-savings derived from NWA implementation as compared to the avoided capital investment.

(IV) For costs the Commission deems to be incurred outside the ordinary course of business, the utility may seek approval of a regulatory asset for recovery as part of the utility's next rate case or may be placed in another cost recovery mechanism as proposed by the utility. The Commission shall establish the authorized rate of return on any regulatory asset created pursuant to this paragraph.

(e) 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.

(f) The utility shall file a final DSP, which may include required modifications, within 60 days of the Commission's final decision.

3539. Security Assessment.

(a) The utility shall provide a narrative assessment of the reliability and resilience of the distribution grid with respect to cybersecurity and physical security, including:

(I) current status of distribution grid reliability and plans for improving reliability, including areas of the grid where reliability problems have been identified, with plans for resolving them. Distribution grid reliability metrics (SAIDI and SAIFI at a minimum) should be provided for each year for the past three years for each substation;

(II) list of major outages, including cause and duration, involving 10,000 customers or more for each year for the past three years;

(III) analysis of cyber security issues or other threats to the distribution system and what efforts the utility is taking to ensure the distribution system is secure;

(IV) analysis of risks by substation posed by natural disasters such as wildfires, floods, severe storms, and a detailed description of efforts the utility is taking to increase system resiliency in the response to these risks;

(V) other plans aimed at improving distribution system resiliency; and

(VI) any pilots or programs, existing or proposed, aimed at increasing reliability and resiliency, using microgrids or other technology, should be discussed within the Grid Innovation section of the Phase I DSP, as described in rule 3533.

(VII) The utility may incorporate by reference any other filings or applications made to the Commission that are relevant to a discussion of distribution system reliability and resilience.

3540. Data Access, Privacy and Confidentiality.

(a) The utility shall disclose data necessary to implement these rules with appropriate levels of protection, considering sensitivity and public benefit. The utility shall identify and address the

treatment of sensitive information in consideration of the objectives of DSP and as required by these rules.

(b) The utility shall not disclose personal information, as defined in paragraph 1004(x), or customer data, as defined in paragraph 3001(i). Paragraph 3033(b) shall not apply to data releases under this rule.

(c) In each DSP application filing made pursuant to rule 3529, the utility shall file a list of the information related to the resource plan proceeding that the utility claims is confidential and a list of the information that the utility claims is highly confidential, and its proposed treatment of the information. For good cause shown, the utility may seek to protect information as confidential or highly confidential by filing the appropriate motion under rule 1101 of the Commission's Rules of Practice and Procedure in a timely manner.

3541. Web Portal.

(a) The utility shall make available a web portal that provide map-based and tabular data that is publicly available or access-restricted as further defined under this rule. Such web portal shall be designed to meet the objectives of the DSP and shall allow users to download data in tabular and geospatial formats

(b) The utility may only deny access to its web portal if visitors and/or registrants violate the terms of service or other agreed upon terms of access. To ensure the appropriate level of protection of sensitive information, the utility may require visitors to the web portal to take actions, including:

(I) requiring visitors to acknowledge terms of service associated with its use, provided those terms do not preclude academic or public policy purposes; and

(II) establishing registration processes, including the creation of a username and password, and/or the use of multifactor authentication for access to sensitive information.

(c) A web portal shall include at least the following information:

(I) consistent with subparagraph 3531(a)(II), the utility's hosting capacity analysis;

(II) publicly available summaries, data, or links to existing information on the utility's website related to programs approved by the Commission that address the deployment of DERs, including, without limitation, pilots, tariffs, and incentives; and

(III) any additional content as directed by the Commission.

(d) Implementation of the web portal.

(I) Prior to filing its first DSP application pursuant to rule 3529, the utility shall engage potential users of the web portal from multiple sectors to develop a proposal for implementation of the web portal to be filed with the application.

(II) In its first DSP application pursuant to rule 3529, the utility shall present a proposal and timeline for developing a web portal that meets the requirements of this rule and includes:

(A) a summary of its process for identifying and engaging potential users of the web portal and the results of that process;

(B) a description of use cases that will be implemented through the web portal to meet the objectives of DSP;

(C) an evaluation of the data required in a DSP application pursuant to rule 3529 that addresses what data will be provided on the web portal and at what level of granularity, an evaluation of the risks and benefits associated with providing such data, proposals for treatment of sensitive information, and identifying any data for which confidential or highly confidential treatment is sought under the process provided in paragraph 3540(c);

(D) a proposal for providing functionalities that enhance the user experience, such as color-coding of substations, circuits, and feeders or ability to change the year of the data being displayed;

(E) a proposal for what information is currently available and can be provided on a web portal and what information requires approval by the Commission for incorporation onto a web portal;

(F) a proposal for updating data provided through the web portal, specifically addressing the quarterly updating of the utility's hosting capacity analysis as described in subparagraph 3531(a)(II);

(G) a proposal for enabling Application Programming Interface (API) capabilities where reasonable and appropriate; and

(H) a proposal for collecting user feedback on an ongoing basis.

(III) In subsequent DSP application proceedings, the utility shall provide an update on the status of implementing the web portal and any proposed changes to functionality and treatment of data. Prior to each application pursuant to rule 3529, the utility is encouraged to engage with stakeholders including users of the web portal, to identify changes.

(IV) The utility shall file an annual compliance report in the most recent DSP application proceeding that provides an update on the status of implementing the web portal, summarizes user feedback, and describes how the utility addressed that feedback, including any updates or revisions to the functionality of the web portal that are anticipated to occur prior to its next DSP application filing.

3542. Evaluation and Reporting.

(a) An assessment of the existing distribution system, as described in rule 3531.

(b) An assessment of Distribution Grid Security, as described in rule 3539.

(c) Starting with its second DSP application, the utility shall describe the 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.

(d) The utility shall report lessons learned from the DSP process and identify ways to improve methodologies through research before the next filing.

(e) Should the utility receive approval for an NWA, a DSP related pilot, or a DSP-related program in a proceeding other than a DSP application, for active projects the utility shall provide in subsequent DSPs:

(I) the name of the project;

(II) a brief description of the project;

(III) the number of the proceeding in which the utility is seeking or has received approval for the project;

(IV) the number(s) of any other proceedings that contain reporting for the project;

(V) the date of project approval, if applicable;

(VI) the total proposed or approved budget; and

(VII) a description of the proposed or approved budget by funding source.

3543. – 3549. [Reserved].