Decision No. C20-0837

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.

NOTICE OF PROPOSED RULEMAKING

Mailed Date: December 3, 2020
Adopted Date: November 25, 2020

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I. BY THE COMMISSION

A. Statement

1. The Colorado Public Utilities Commission issues this Notice of Proposed Rulemaking (NOPR) to amend the Commission's Rules Regulating Electric Utilities, 4 *Code of Colorado Regulations* (CCR) 723-3 (Electric Rules). The proposed amendments develop new rules regarding Distribution System Planning (DSP).

2. The purpose of this NOPR is for the Commission to solicit comments on the proposed DSP Rules, as described in this Decision and its attachments, and to schedule a rulemaking hearing. Interested persons will have opportunities to submit written comments on the proposed rules and to provide oral comments at the scheduled hearing. The Commission welcomes the submission of alternative proposed rules, including both individual proposals and consensus proposals joined by multiple stakeholders. Participants are encouraged to provide redlined rules if possible.

3. This rulemaking satisfies the requirements of Senate Bill (SB) 19-236, codified at § 40-2-132, C.R.S., that requires the Commission to adopt rules regarding Distribution System Planning. Specifically, SB 19-236 directs the Commission to promulgate rules establishing the filing of Distribution System Plans and the evaluation of Non-Wires Alternatives (NWA). Section 40-2-132, C.R.S., specifies that the Commission shall promulgate rules establishing the filing of a distribution system plan that includes:

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 should be included 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.

B. Background

1. Calls for Integrated Distribution System Planning

4. The Commission explained in Decision No. C19-0957, which opened the DSP Stakeholder Outreach Proceeding (19M-0670E), that it had heard from parties in previous proceedings on the need for exploring an Integrated Distribution System Planning process. In Public Service's 2015-2016 Demand Side Management (DSM) Plan Application proceeding (Proceeding No. 14A-1057EG), Western Resources Advocates (WRA) recommended in its exceptions to Decision No. R15-0496, that the Commission consider a future rulemaking proceeding to establish a public distribution planning process that would require the utility to consider stakeholder input in its distribution system planning, similar to the existing transmission planning process identified in Rules 3625- 3627, 4 CCR 723-3.

5. The concept of distribution planning also came up during the miscellaneous proceeding on Net Metering (Proceeding No. 14M-0235E). Several parties provided the Commission information on the benefits of distribution planning, including WRA, SolarCity (now Tesla), and National Renewable Energy Laboratory (NREL). Additionally, we note that the approval of Advanced Grid Intelligence and Security (AGIS) in Proceeding No. 16A-0588E, requires the Commission to examine how such systems should be used in an effort to develop an integrated distribution system to ensure numerous potential consumer and system benefits of grid modernization investment. AGIS included the integration of new utility systems such as Advanced Distribution Management Systems (ADMS), Advanced Metering Infrastructure (AMI), and Integrated Volt-VAR Optimization (IVVO).

6. In Proceeding No. 17M-0694E[1], the Commission's review of its Electric Resource Planning, Qualifying Facilities, Renewable Electricity Standard, and Interconnection Rules, the Commission also examined the implementation of an Integrated Distribution System Planning process. In that Decision, the Commission invited comment on the concept of distribution grid planning and "initial regulatory steps that the Commission should take to ensure that investor-owned electric distribution systems have the capability to handle increased penetration of distributed generation, storage, and certain load-building technologies such as electric vehicles."

7. Through a stakeholder and outreach effort that began in the spring of 2018, the Commission solicited input and explored many topic areas regarding distribution system planning. A DSP workgroup was formed and the ongoing effort and recent utility filings revealed the benefits of more thorough and transparent distribution system planning processes.

8. WRA submitted proposed model Distribution System Planning rules in the pre-rulemaking Proceeding No. 17M-0694E. WRA noted in its initial comments that the proposed rules were discussed with a number of stakeholders, including Clean Coalition, Colorado Solar Energy Industry Association (CoSEIA), Vote Solar, the Colorado Energy Office (CEO), Energy Outreach Colorado (EOC), Colorado Independent Energy Association (CIEA), and others. WRA contends that DSP should meet the following goals: 1) provide an opportunity for additional oversight and cost control for large investments in the distribution grid; 2) provide an opportunity for more holistic planning and preparation surrounding the proliferation of DER, including an examination of how DER can impact grid reliability and resilience; 3) provide an opportunity for utilities to conduct pilots in order to gain experience and comfort with new technologies; and 4) review, in detail, the reliability and resilience of the distribution grid, by city

[1] Proceeding No. 17M-0694E initiated through Decision No. C17-0878, issued October 26, 2017

and neighborhood, and identify areas where the reliability needs improvement should be identified and targeted for investment.

9. CEO stated in its comments in 17M-0694E that it believes DSP is in the best interest of Colorado ratepayers and that the time is ripe for the Commission to adopt rules governing a DSP. CEO's proposed draft DSP rules established a process to review utility management of the distribution grid to ensure cost effective investments that support grid reliability and resilience and diversification of energy supply; support utilization of distributed energy resources that reduce the need for conventional distribution grid investment; encourage local ownership or renewable generating facilities; provide transparency of grid investments and capabilities; and facilitate the modernization of grid monitoring and control technologies and processes.

10. The Joint Solar Parties filed comments in support of the new DSP proposals WRA has submitted, and stated it would submit additional comments in reply on any specific areas where they can identify improvements.

11. Energy Freedom Colorado filed comments and attachments in support of the development of rules regarding Hosting Capacity Analysis (HCA).

12. Through the stakeholder outreach and workshop process that ended in late 2018, the Commission and stakeholders developed an understanding that the adoption of distributed energy is accelerating due to changes in customer choices, technological development, cost reductions, and public policy. DSP may help the Commission ensure that grid modernization allows for continued safe, reliable, and cost-effective utility operations. An integrated planning approach across discrete aspects of utility operations may help the utilities, the Commission, and stakeholders meet distribution needs and expand customer choice through: (1) integrating DER

into grid planning; (2) streamlining the interconnection process; (3) utilizing new resources to increase demand flexibility; and (4) avoiding unneeded investment in transmission and bulk power generation.

13. As a result of the stakeholder process, many stakeholders concluded that an Integrated DSP process is an important step for the Commission to take. As more DER are added to utility systems because of technological development, cost reductions, public policy, and customers interested in having more choices, stakeholders include that DSP may be an integral part of a systematic approach to meeting this growth in adoption. Comments further discuss that increasing DER is not the only reason for requiring integrated distribution planning. Many states across the country see such DSP as a way to better engage customers, cut costs and improve reliability and resiliency. Others state the driver for such a process is a means to achieve cost-effective grid modernization or a way to replace aging infrastructure.

2. 2019 DSP Stakeholder Outreach Proceeding

14. On December 3, 2019, the Commission opened Proceeding No. 19M-0670E (DSP Stakeholder Outreach Proceeding) as an administrative proceeding to collect comments and other information given statutory changes in SB 19-236. The Commission designated Chairman Jeffrey Ackermann as Hearing Commissioner, pursuant to § 40-6-101(2)(a), C.R.S., to work with the Staff of the Colorado Public Utilities Commission (Staff), stakeholders, and other interested participants to collect and organize information, conduct public comment hearings, and make recommendations to the full Commission s to possible next steps in promulgating rules required by § 40-2-132, C.R.S.

15. Approximately 23 organizations and individuals participated in the DSP Stakeholder Outreach Proceeding. Public Service, Black Hills Colorado Electric, Inc. (Black

Hills), the Colorado Rural Electric Association (CREA), and Holy Cross Electric Association, Inc. represented the Colorado electric utilities. The Colorado Office of Consumer Counsel (OCC), the Colorado Energy Consumers Group (CEC), Walter M. Sharp, Larry Miloshevich, and Karey Christ-Janer, represented various consumer positions. Environmental and renewable advocacy groups included Western Resource Advocates (WRA), Advanced Energy Economy Institute (AEE), Vote Solar, the Southwest Energy Efficiency Project (SWEEP), and the Colorado Renewable Energy Society (CRES). Participants also included trade organizations and non- utility providers of electricity services, such as the Colorado Solar and Storage Association and Solar Energy Industries Association (COSSA/SEIA), Namaste Solar Electric Inc., Uplight, Inc., and Recurve, Inc. The IBEW Local No. 111 represented certain labor interests. The CEO, City of Boulder (Boulder), and City and County of Denver (Denver) also participated in the Stakeholder Outreach Proceeding.

16. Participants in the Stakeholder Outreach Proceeding provided multiple rounds of written comments and participated in workshops and working groups. Participants also were encouraged to collaborate in developing consensus rules and identifying participant conflicts in topic areas.

17. In accordance with the Commission's directives in Decision No. C19-0957, participants in the DSP Stakeholder Outreach Proceeding offered comments on the scope of the Commission's examination of proposed Distribution Planning Rules. Participants were encouraged to provide comments that are responsive to the following issues:

1) Guidance or policy statements regarding the purpose of initiating a DSP process;
2) Issues surrounding NWAs;
3) Modeling load growth, DER forecasts and scenario analysis;
4) What needs to be included in DSP filings, and frequency of filings;

5) Data, data privacy, and data security issues;
6) Developing a cost-benefit framework;
7) Hosting Capacity Analysis (HCA) and Interconnection;
8) Coordination of filings and suggestion of other issues this proceeding should address; and
9) How often plans should be updated.

18. Initial Comments were filed by Larry Miloshevich, Denver, Karey Christ-Janer, COSSA/SEIA, Black Hills, CEO, AEE, Vote Solar, WRA, IBEW Local No. 111, SWEEP, the OCC, and Public Service.

19. Reply Comments were filed by Larry Miloshevich, COSSA/SEIA, Black Hills, Recurve Analytics, Inc., Denver, Vote Solar, Karey Christ-Janer, WRA, AEE, CEO, Colorado Energy Consumers and Public Service.

20. Public Service, WRA, CEO, and COSSA/SEIA all filed draft redline rules.

21. Through Decision No. R20-0301-I, issued April 28, 2020, a schedule for two virtual workshops and supplemental filings requested of the utilities were scheduled. The Decision also requested a final round of comments based upon the two workshops, as well as responses to the draft rules that have been submitted by various participants to be submitted by June 30, 2020.

22. The First Workshop was held on May 22, 2020, and focused on determining what the utilities need to file in their initial detailed DSP filing. Prior to the first workshop, we requested that the jurisdictional electric utilities submit what each considers its current DSP or equivalent in order to facilitate the Commission's understanding of current distribution planning practices by jurisdictional utilities in Colorado. Commissioner Matthew Schuerger of Minnesota, along with Staff from the Minnesota PUC and the Rhode Island PUC, provided their perspectives on the regulation of distribution system planning. Perspectives on Hosting Capacity

Analysis were provided by both the Interstate Renewable Energy Council (IREC) and the Electric Power Research Institute (EPRI). Both Public Service and Black Hills provided summaries of their current distribution planning processes.

23. The second workshop was held on June 12, 2020, and focused on the development and analysis of NWA. The Commission invited utilities, stakeholders, and outside experts to present on an "Envisioned NWA Project." In addition to participation in the workshop, the Commission requested that each jurisdictional utility present data and information describing specific situations where NWA options were considered in order to facilitate the Commission's understanding of how NWA's are currently integrated into the jurisdictional utility's distribution system management.

24. Presentations on current NWA projects and their potential were provided by representatives from Recurve and Sunrun. A summary of current state practices on NWA and cost benefit analysis was given by Levelized Consulting. Presentations on an "Envisioned NWA Project" under a formal DSP process here in Colorado were provided by Public Service, WRA, and COSSA.

25. Following the workshops, the Hearing Commissioner issued Decision No. R20-0479. This Decision explained the Commission's desires to understand more discretely how current distribution planning processes are conducted, in order to most effectively craft rule language for the distribution planning process that balances regulatory oversight and addresses the statutory directives. In addition to responding to issues discussed during the workshops and responding to redline rules filed in this proceeding, the Decision requested participants to provide comments that are responsive to questions concerning utility distribution system planning practices in Colorado.

26. Final Comments were filed by Larry Milosovich, Boulder, CEO, COSSA/SEIA, Black Hills, AEE, WRA, SWEEP, CEC, Karey Christ-Janer, and Public Service.

27. On October 1, 2020, at its weekly meeting, the Commission closed the DSP Stakeholder Outreach Proceeding and instructed Staff to prepare recommendations for this NOPR.

C. Discussion

28. As set forth in Rule 3207, 4 CCR 723-3, the Commission currently considers all distribution system investments to be in the "ordinary course of business" and therefore exempt from CPCN requirements under § 40-5-101(1)(a)(III), C.R.S.

29. However, as several stakeholders have noted, the utilities currently engage in developing an internal, five-year distribution plans. Neither stakeholders nor the Commission have an opportunity to provide input on that plan.

30. We find it necessary to open this rulemaking for several reasons. We conclude that a comprehensive rulemaking is required for the Commission to satisfy its obligations pursuant to SB 19-236 concerning the filing of Distribution System Plans. We also agree with the commenters in the Stakeholder Outreach Proceeding that a comprehensive rulemaking is appropriate at this time to support the state's broader policy goals. Working toward the proposed goal of creating greater transparency into the capacity and capabilities of the current distribution system as well as distribution system investments will allow the Commission to ensure that utilities are making investment decisions that are in the public interest and support state policies, including its greenhouse gas reduction, renewable energy, and transportation electrification goals.

31. The Commission proposes Distribution System Planning Rules as outlined in Attachment A (in legislative format) and Attachment B (in final format). These proposed rule changes are explained in the balance of this Decision.

32. The Commission has developed these proposed rules to enhance transparency and accountability in the DSP process. We believe 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 interconnection of DERs by customers and third parties and strive to optimize the use of new resources, non-wires alternatives, and emerging grid technologies while reasonably balancing the risks and opportunities.

1. Distribution System Planning (DSP) Rules

a. Stakeholder Perspectives

33. Public Service commented in the Stakeholder Outreach Proceeding that its proposed rules provide the Commission with an efficient and statutorily-consistent approach to DSP that creates efficiencies with existing processes and creates a flexible, comment-based, non-litigated approach to the DSP filing. Public Service believes this approach is worth serious consideration and one that is appropriate in this dynamic period of energy policy change. Public Service states that its aim is to implement DSP Rules that ultimately can be responsive to the distribution needs of the Commission, the Company, its customers, and the communities that it serves as well as not creating a new excessive and recurring proceeding that will consistently draw a great deal of resources from the Commission and the regulatory community.

34. Public Service adds that it envisions a flexible DSP process that can accommodate new projects between plans and will place those projects in an applicable planning application or

by separate application. They argue that having a more flexible DSP process, rather than one that promises lengthy scheduled litigation, will yield a process that can be much nimbler to the needs of customers and the communities they live in.

35. Black Hills commented in the Stakeholder Outreach Proceeding that it is in the early stages of its transition to a more dynamic distribution system. During the first workshop, held on May 22, 2020, Black Hills discussed, at a high-level, its long-term strategy to manage the evolving system and its transition to a more dynamic two-way distribution grid. Black Hill's long-term vision, called "READY Grid," is based on five pillars: reliability, grid safety, security, customer solutions, and affordability. Black Hills states that these pillars form the Company's future state capabilities and will lead the prioritization of future investments. Black Hills further states that once a problem/need or constraint is identified on the system, the sources of potential options brought in for consideration have been successful in ensuring safe, reliable, and cost-effective solutions. Black Hills believes that it uses industry best practices to ensure the solutions are appropriate to address the issue at hand. Black Hills also emphasizes that a one-size fits all approach to DSP is not suitable for two utilities with very different customers and size.

36. WRA responded to Public Service's proposed rules and comments in the Stakeholder Outreach Proceeding, stating the most foundational problem with Public Service's proposed rules is the position that DSPs should be mere "informational" filings. WRA argues this approach creates a lack of Commission and stakeholder involvement that undermines the efficacy of DSP. Under Public Service's proposal, once a DSP is filed, WRA describes that interested individuals would have 30 days to provide comments on the DSP. Commission Staff would then review the DSP and all comments and make a recommendation to the Commission to either: (1) approve the DSP as submitted; or (2) require amendment of the DSP, but only insofar

as necessary to "meet the requirements of Rule 3637(c). WRA argues that Public Service seeks to remove all discretion from the Commission and create a construct in which the only ground for rejecting a DSP is a finding that the DSP is incomplete. WRA believes that under Public Service's construct, DSPs are purely informational, and there is an exceedingly narrow role for the Commission in evaluating DSPs. WRA strongly objects to such a process, as it would render the DSP largely meaningless.

37. CEO also took issue with Public Service's proposed process, arguing against the Company's suggestion that distribution system planning be treated the same way as transmission planning. CEO argues the statutory requirements for distribution system planning are different than the requirements for transmission planning and therefore necessitate a more robust process. CEO adds that the Colorado General Assembly has required the Commission to undertake distinct actions in response to DSPs that culminate in a more rigorous review process for DSPs than is presently required in transmission planning.

38. The OCC stated in the Stakeholder Outreach Proceeding that the Commission should consider the ongoing development of an intelligent grid, and wherever possible look to grid development that maximizes the use of grid infrastructure to control load. Through the shaving and shifting of peak, the Commission has an opportunity to pass along savings to ratepayers while encouraging utilization of increased renewable energy sources. Additionally, these resources could be targeted and optimized to reduce grid operating expenses, improve revenue assurance and increase customer-facing options to reduce their own utility bills, such as customer interface platforms and new demand-side management options.

39. To identify these capabilities, OCC believes the Commission could direct the utility, as part of its reporting, to discuss capabilities, costs and benefits in its narrative and

propose metrics related to these topics. Alternatively, OCC suggests the Commission could ask the utility to outline and describe its efforts to reduce peak. For example, the utility might describe its demand response events for the reporting period or the utility could describe its electric vehicle managed charging efforts and its effect on system peak load.

40. While the questions were not specifically posed in Decision No. C19-0957, several participants provided comments on the importance of developing a stakeholder process for DSP. Public Service stated that it will continue to commit to an open, transparent and collaborative process for involving stakeholders in its distribution planning process. To reflect this objective, Public Service states that it has written outreach steps into its proposed DSP rule. Public Service proposes to hold stakeholder meetings prior to the filing to review the preliminary plans and seek meaningful input from those stakeholders for consideration in the DSP filing. Public Service states it will also place information on its corporate website with information on how stakeholders can provide written comments.

41. Boulder recommended in the Stakeholder Outreach Proceeding that utilities be required to formally engage with municipal governments and interested community organizations as part of the distribution planning process. Boulder believes this engagement should include annual meetings of utility distribution system engineers, customer product developers and community account representatives with municipal employees and community organizations, such as residential and commercial real estate developments (including operators of affordable housing), climate and resilience advocacy organizations and public and private transportation planners and operators.

b. Rule 3526. Overview and Purpose[2]

42. Decision No. C19-0197 stated that Distribution System Planning is occurring in various states, and has been initiated for various purposes. The experiences in these other states has demonstrated that the stated purpose for initiating DSP, such as policy and regulatory objectives, influences how DSP is designed and ultimately implemented. The Decision noted that § 40-2-132, C.R.S., does not explicitly state a purpose for implementing DSP. Participants in the DSP Stakeholder Outreach Proceeding were asked to comment on the purpose of implementing a DSP, what types of guidance should the Commission provide to utilities, and what principles should the Commission consider in setting criteria to govern the review and approval of a DSP.

43. The Initial Comments filed in response to the Commission's questions were generally aligned on the purpose of distribution system planning. The main difference between participants' purpose statements seemed to be whether the purpose of DSP is to proactively promote DER adoption and the state's carbon reduction goals. Each set of redline rules submitted by WRA, CEO, and COSSA used similar language in their Overview and Purpose sections.

44. Public Service stated that the purpose of future DSP rules in Colorado should be to provide additional information on the electric distribution planning process, to enhance planning as DER implementation continues, and to provide the opportunity to examine the costs and benefits of some conventional distribution system investments, as well as potential alternatives to those conventional distribution system investments, where such alternatives are feasible and beneficial.

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[2] The subheadings in this section of the Decision correspond to the subheadings in the reorganized rules.

45. Participants provided other recommendations in filed comments for consideration by the Commission when reviewing or approving a DSP. These included: encouraging more active communication between utilities and the communities they serve; avoiding slowing or delaying other utility planning activities and proceedings; maintaining system safety, reliability, resilience, and security; establishing cost-benefit analysis; ensuring DSP creates value for customers; and providing flexibility and adaptability so that processes can be adjusted as more information is learned. In addition, there is general agreement with the need to promote market-based innovation, as well as reduce emissions, including greenhouse gases.

46. Black Hills asserted that the purpose of the DSP is to provide regulators and various stakeholders visibility and transparency into the utilities' distribution system needs and facilitate a review of the utilities' long-term distribution system planning. Maintaining and improving the safety, reliability, and security of the distribution system at a reasonable cost should be the primary goal or objective of any DSP.

47. The OCC commented that the purpose of implementing rules around DSP is to create a process to modernize the grid in a manner that will protect safety, reliability and resiliency as the energy sector transitions toward the state's decarbonization goals in a cost-effective manner that benefits ratepayers.

48. We propose language in Proposed Rule[3] 3526 that 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 defined purpose of 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 distributed energy resources, expanding the utilization of non-wire alternatives that reduce the need for conventional distribution grid investment and preparing for new expectations upon the system. It is anticipated that 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, to modernizing grid monitoring and control technologies and processes. DSP is intended to be complementary to, but not a replacement for, existing Demand Side Management planning and programs and/or distributed generation acquisition processes approved as part of Renewable Energy Standard plans, as well as Transportation Electrification plans which are elements of Electric Resource Planning.

c. Rule 3527. Definitions

49. 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.

50. In its proposed redline rule, Public Service defined only those terms required by the statute. Other participants expanded on the needed definitions and were generally aligned on those required definitions in DSP rules with minor differences. WRA states its proposed rules would add several new definitions to the five currently legislatively required definitions. WRA argues that it is important to define these terms, many of which are relatively nascent nomenclature and may have not been defined elsewhere in the Commission's Rules Regulating

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

Electric Utilities. They describe specific distributed energy resources technologies or elements of a DSP which are used in the remainder of WRA's proposed rules.

51. We propose eighteen new definitions modeled after the proposed definitions submitted by participants in the DSP Stakeholder Outreach Proceeding. We also add "Demand Flexibility", and "Locational Value" to proposed Rule 3527. We find that it is important to provide a unique definition for Demand Flexibility, as a unique concept from traditional Demand Response (DR). While traditionally, programs and pilots related to DSM and DR were suitable in a DSM or a Transportation Electrification Plan (TEP) proceedings, we note that a DSP plan may also be an appropriate proceeding to deal with programs and pilots that enhance the flexibility of both DSM and DR, with the growing ability of being able to use communication and control technology to shift electricity use across hours of the day while delivering end-use services using beneficial electrification, such as controlled EV charging. We find a definition of Locational Value important as the experience with HCA grows and matures, pilots, programs and tariffs could be developed to target DER where they provide the best value to the distribution grid.

52. We note that the definition of Distributed Renewable Electric Generation, which was directed by SB 19-236, is now defined in Rule 3001.

d. Rule 3528. Distribution System Plan Filing Requirements

53. Decision No. C19-0957 asked participants in the DSP Stakeholder Outreach Proceeding for comments on basic requirements for the submission of a DSP filing as directed by § 40-2-132, C.R.S. WRA, CEO and COSSA propose the Commission require a DSP every two years, with the first Plans to be submitted on or before January 1, 2021. Public Service and Black Hills propose every four years.

54. WRA believes a two-year time frame ensures the utility is timely in identifying opportunities for and assessing the value of NWA opportunities and progressing on its grid innovation work, without being overly burdensome. Such a time-frame would also allow for DSP forecasts to feed in to ERP forecasts, which are made every four years. CEO agrees with WRA, stating this will allow a DSP to be coordinated with other utility plans so information from distribution system planning will be taken into consideration in electric resource plans, renewable energy standard compliance plans, demand-side management plans, beneficial electrification plans, transportation electrification plans, and transmission plans.

55. Public Service suggests a four-year interval between DSP filings accounts for the amount of time and effort it takes to compile the data. RES and resource plans are also scheduled to occur on a four-year cycle. Public Service adds that DSPs should not in any way interfere with utilities' plans and normal-course-of-business efforts to preserve reliability and meet new demands and interconnection requests, especially in the short term.

56. Black Hills agrees with Public Service's recommended approach. Black Hills also states that in setting the criteria to govern the review and approval of a DSP, the Commission should principally consider the timing and cost of when investments are needed. A lengthy Commission approval process could lead to inefficiencies and result in potential safety and reliability issues. To address this concern, Black Hills believes Commission consideration of the long-term distribution system planning (five - ten years) for major distribution capital infrastructure needs could be reviewed and approved by the Commission in an appropriate amount of time in advance of when the infrastructure is needed.

57. The OCC suggests that distribution system plans should be filed every two to three years with an annual update. Each plan should lay out a short-term (up to five years) action plan for distribution system investments and a long-term outlook (typically ten years).

58. In response to Public Service's proposed four-year cycle, WRA argues a four-year gap between filings will lead to key information going stale and will result in missed opportunities to take advantage of fast-changing grid-edge technological solutions. In addition, WRA states distribution grid investments tend to have timelines of two to three years, where the utility identifies a need and immediately starts a process to address the need with traditional investments in new capacity. WRA also believes a four-year filing requirement may result in slower utility testing of innovative grid technologies.

59. In Rule 3528, we propose that the utility files a Distribution System Plan as an application every two years, with the first plan to be submitted on or before October 1, 2021. We agree with many of the participants who argued that the utilities, stakeholders, and Commission must utilize each plan to take advantage of fast-changing grid-edge technological solutions. We acknowledge that as the DSP process matures, a two-year cycle may no longer be required and the Commission commits to revisiting these requirements once more experience with the process is gained. We also believe a two-year cycle will help DSP coordinate with other utility plans so information from each proceeding will be taken into consideration in electric resource plans, renewable energy standard compliance plans, demand-side management plans, beneficial electrification plans, transportation electrification plans, and transmission plans.

60. We also propose Rule 3528(d)(I-IV) to allow for flexibility for certain filing requirements that may not yet be practicable or are cost-prohibitive in the early stages of DSP.

Commission Staff will have the opportunity to review the content of the plan, as well as the reasoning for withholding certain filing requirements via proposed Rule 3528(d).

61. We seek comment on the following questions:

- How should the Commission evaluate the length of time needed between subsequent DSP filings after the first round of DSP plans are submitted?
- Should the Rules include specific requirements for utilities on stakeholder involvement?

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

62. 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. Decision No. C19-0957 specifically asked for participant comments on how utilities are currently conducting load forecasting and forecasting of DER growth. We also asked about options and the corresponding costs and benefits of increasing granularity of load forecasts and using alternative methods, including customer adoption methods, for projecting DER adoption scenarios. The utilities were asked to describe how they currently evaluate potential NWA projects in distribution planning.

63. Many participants were in agreement with the guidance requirements concerning contents of a DSP provided in CEO's initial comments in the Stakeholder Outreach Proceeding. CEO describes a high level summary of 11 sources of minimum information utilities should include a DSP. The utilities responded that the Commission should focus on requirements that provide the highest value while preserving needed flexibility to plan and operate their systems.

64. Public Service proposed its DSP contain the following: Historical Distribution System Analysis, Forecast Distribution System Analysis, Major Distribution Grid Capacity Projects, Non-Wires Alternatives Analysis, Innovation, and Pilot Programs.

65. Proposed Rule 3529 lists the required contents of each plan. Those requirements are further detailed below and include: distribution system forecasts, as described in Rule 3530; an assessment of the existing distribution system, as described in Rule 3531; an assessment of grid needs, as described in Rule 3532; a summary of its grid innovation plans, as described in Rule 3533; a NWA cost benefit methodology, as described in Rule 3534; an action plan, as described in Rule 3535; NWA suitability screening, as described in Rule 3536; a proposal for cost recovery, as described in Rule 3537; and a security assessment, as described in Rule 3538.

f. Rule 3530. Distribution System Forecasts.

66. SB 19-236 requires the utility to provide "a forecast of the growth of distributed energy resources for the years covered by the plan".

67. Public Service details that at a distribution planning level, DERs are forecasted using a "bottom-up" approach based on customer applications. Public Service points out that long-term DER forecasts are being performed by several utilities with mixed results, in part due to the fact that load is easier to forecast than DERs for several reasons. Public Service states that its load growth tends to occur in specific areas where there is new construction, whereas DERs can be installed anywhere on the system, even in a mature, built-out area where new construction is not present. It further argues that the location of the DER installation significantly affects how it impacts the overall distribution system, so the forecasts need to be geographically specific. Public Service comments that over time, it will make sense to provide more granular forecasts of DERs as tools emerge and the market develops and becomes more predictable.

68. Black Hills agrees with Public Service's comments that the type of "top-down" forecast of high levels of electrification and/or DER could potentially be useful for long-term planning purposes, but such forecasts should not be used to justify distribution system

investments. Black Hills believes that forecasts are assumption laden, and engaging in distribution investments based on them may lead to stranded costs, which are paid for by customers. In addition, Black Hills adds that forecasting DER growth is inherently different than forecasting load, as load growth tends to be more geographic in nature and predictable.

69. In its comments, SWEEP adds that transparent load growth forecasts are an essential component of a DSP and enable a realistic assessment of NWAs. Stakeholders should have the opportunity to review and provide input into forecasting assumptions used by utilities. In addition, load forecasts should be provided at the feeder-level. As described in Rule 3638 of WRA's proposed rules, utilities should develop load forecasts under at least three growth scenarios and should consider growth in distributed generation and beneficial electrification of buildings and transportation.

70. The OCC suggests each utility run low, mid, and high growth forecasts, with growth rates specific to different regions of a utility's territory. This would allow the utility to model areas of projected growth in its territory in order to identify areas of the system that may be more at risk and, therefore, more in need of infrastructure upgrades. The OCC recommends the utilities incorporate growth patterns and drivers outside of their historical experience when forecasting load growth.

71. We agree with participants in the Stakeholder Outreach Proceeding that accurate load growth and DER growth forecasting is foundational to the DSP process because it defines the needs of the system over the planning period. It also provides an important link between DSP and ERP proceedings to ensure consistent assumptions and modeling. Such forecasts will need to be spatially and temporally differentiated to enable a proper assessment of system needs and potential solutions. We further understand that the uncertainty of the types, amount and pace of

DER expansion make singular deterministic forecasts ineffective for long-term distribution investment planning.

72. We thus propose 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 project load ten years into the future, with data to be provided for each year over the ten-year span. We would like the utilities to provide a reference to the load growth scenario modeled in their latest ERP to allow the Commission to see consistency across proceedings, or to specifically understand why a different scenario is being presented. We generally agree with the forecast requirements provided in proposed rules by WRA, COSSA/SEIA and CEO.

73. We seek comment on the following questions:

- How should the Commission, utilities and stakeholders frame existing or new state policy goals in a High Adoption scenario?
- Should goals such as EV deployment, beneficial electrification, renewable energy, GHG and/or Carbon reductions be included in medium and/or high growth scenarios?
- Should the targets of EV adoption, beneficial electrification and renewable energy contained within the Governor's Roadmap related to HB 19-1261 GHG targets be considered state policy goals as they relate to DSP?
- What factors are important to be included in the utility's forecasts?
- Should the company identify which load forecast matches the load forecast used in the company's last ERP? If there is variation, how should that be addressed?
- How do local land-use, zoning, and code decisions currently inform utility load and capital forecasts?
- Are there opportunities within local government processes around land use, zoning, and code adoption in which utilities could be involved to promote more efficient capital planning, and if so, should that be a type of allowed non-wires alternative?

g. Rule 3531. Assessment of Existing Distribution System.

(1) System Overview and Substation Historical Data

74. SB 19-236 requires that a utility's Distribution System Plan report certain data on its distribution system, including: system and substation historical data, peak demand, adoption of Distributed Energy Resources, and Distribution System Investments.

75. CEO suggests that the rules also include a summary of Major Distribution Grid Projects, which include a narrative description of current, planned or proposed, as well as those that meet NWA suitability screening criteria. In addition, CEO suggests requiring the utilities to provide a five-year action plan for distribution system investments and activities, which will serve as a guiding document for the Commission and stakeholders to rely upon when evaluating distribution system planning and investment decisions.

76. The OCC filed as an attachment a comprehensive list of information that should be required by the Commission. The OCC comments that information is imperative to the successful implementation of distribution system planning and grid modernization efforts to ensure cost-effective decisions. The OCC recommends the data should be reported both for the reporting period as well as historically for comparison and trend identification.

77. We agree with many participants that a key step in the DSP process is to characterize the capabilities and limitations of the existing distribution system. This requires a detailed review of the capacity of existing infrastructure, as well as known problems, limitations and areas of concern.

78. Proposed Rule 3531(a)(I) requires each utility to identify and assess major distribution grid capacity needs by providing 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 maps would be made available on the utility's web portal as described in Rule 3542. The assessment should also include the status of advanced metering infrastructure deployment by customer class and updates on meter data management systems.

79. We seek comment on the following questions:

- In order to provide an indication of whether any capacity constraint is of long duration or only happens for a few hours a year, should the Commission require the utilities to add load factor or load duration curve for each feeder & substation transformer to its system overview?

(2) Hosting Capacity Analysis

80. Decision No. C19-0957 posed several questions regarding hosting capacity analysis (HCA) and the interconnection process. The Decision states that HCA determines the maximum amount of DER that can be interconnected at a specific point in the distribution system without adversely impacting power quality or reliability under existing control and protection systems and without additional upgrades. HCA also reveals areas where DER is less costly to interconnect. Hosting capacity maps can help streamline interconnection processes and create an environment that encourages the addition of DER and NWA to the grid.

81. Public Service notes that its HCA process serves as a first step for solar developers to help identify areas where solar capacity is likely available. Public Service recommends an annual update to the HCA and believes that this frequency is appropriate balancing the value that it provides and the level of resources that are needed for every update. Public Service argues that if greater frequency is required, it will have to add additional resources and thus adds more cost to the HCA process.

82. In its comments responding to HCA related questions posed by Decision No. R20-0497-I, Public Service states it is developing a project with EPRI to help identify the next logical steps of progression for moving from its current capabilities to a new level to meet future objectives. An expected outcome is to help understand what tools and processes are needed to move to increased levels of capabilities. Separately, Public Service states it is also participating in an EPRI research project that will examine how advanced inverter functions enabled through adoption of the IEEE-1547-2018 standards could provide benefits to the distribution feeders and potentially increase hosting capacity.

83. Black Hills notes that it currently does not have software capability to provide hosting capacity maps and the use of hosting capacity maps and the timing of that use can and should differ between Black Hills and Public Service. It argues that imposing the same hosting capacity analysis requirements on the same timetables will impose more significant cost on Black Hills' customers. Black Hills adds that it has a good working relationship with its local solar developers and installers and it regularly shares information with the local developers on an informal basis. Rather than take a prescribed approach from a non-local organization, Black Hills states it prefers to continue its successful work with local solar developers and installers and customers to identify their needs.

84. CEO recommends that a utility propose use cases for the HCA in its DSP, along with its proposed HCA methodology. CEO suggests that the Commission provide interveners an opportunity to respond to the proposed use cases and to propose new uses cases that should be included in the plan. CEO believes that more frequent updates would improve the value of HCA by ensuring that data presented is more up-to-date. For example, more frequent updates could help avoid issues of siting or interconnection of DERs that may arise from data on hosting

capacity for a feeder or substation being out-of-date. Therefore, CEO believes that if more frequent updates are technically feasible at a reasonable cost, the frequency should be increased.

85. COSSA/SEIA believe a DSP should include benchmarks for interconnection speed, interconnection upgrade deferral, and load growth deferral. The Commission should review benchmarks and accountability with each updated DSP, adding new metrics as necessary to ensure that risks are being appropriately addressed, including risks to reliability and resiliency.

86. AEE comments that HCA represents a timely move towards greater utility system transparency and collaboration between stakeholders in the energy ecosystem. AEE believes that HCA helps bridge the information gap between developers, customers, and utilities by providing greater access to actionable distribution system data. This facilitates development of DERs at lower costs, and supports opportunities for customers and third-party DER providers to provide products and services to utilities to meet grid needs. AEE argues that is important to define the use cases for HCA prior to determining the criteria for implementation, crafting a methodology, and gathering and updating data. AEE adds that clearly defined use cases allow all stakeholders to get the most value out of HCAs and achieve their strategic objectives while best balancing cost and complexity.

87. We agree with many of the participants in the Stakeholder Outreach Proceeding that hosting capacity analysis should be used to establish a baseline of the maximum amount of DER, including portfolios of DER, an existing distribution grid (feeder through substation) can accommodate safely and reliably without requiring infrastructure upgrades. A hosting capacity analysis will also streamline the interconnection process, as proposed projects with a nameplate capacity below the available capacity can be processed more quickly.

88. We further view HCA is a critical analytical tool that can help the Commission, utilities, developers and other stakeholders gain greater visibility into the current state of the distribution grid and its physical capacity to host DERs. Therefore, we propose Rule 3531(a)(II) that requires the utilty to develop a distributed generation HCA of the distribution system. The HCA 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.

89. The results of the HCA would be displayed visually in the form of a map, which color-codes feeders or line segments according to their hosting capacity range, published with accompanying datasets containing the more detailed underlying data. The HCA maps and accompanying data would be made available on the utility's web portal as described in Rule 3542.

90. Rule 3531(a)(II) specifies that the utilty 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 PV and electric storage systems), how the utilty 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 the annual HCA.

91. We are aware that the utilities' HCA portals/maps initially may be limited in terms of data granularity and data refresh rates, but, as more grid data are available and existing DER characteristics are included in the analysis, we expect that the HCA will become a more accurate

representation of the grid. This will provide the Commission, utilities, developers and stakeholders more functionality and usefulness from these HCA requirements.

92. We seek comment on the following questions:

- How should the Commission use feedback from HCA users to increase the accuracy and value of the analysis?
- How should the Commission develop rules allowing for flexibility regarding HCA where it may not be economic in certain geographic areas.
- In lieu of requiring voltage and power quality data, should the Commission require a summary of the number of voltage excursions or other power quality metrics?
- Should the baseline conditions and assumptions underlying the HCA be transparent and available for stakeholders to comment?

h. Rule 3532. Grid Needs Assessment

93. In the Stakeholder Outreach Proceeding WRA described a Grid Needs Assessment (GNA) as a summary section for utilities to provi,de analysis and data regarding current and future constraints on the distribution grid and identify solutions to those constraints, including possible NWA solutions. The purpose of this Rule is to identify where constraints are emerging 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.

94. We agree that a bi-annual distribution planning effort involves two general components: 1) multiple scenario-based studies of distribution grid impacts to identify “grid needs”, and 2) a solutions assessment including potential operational changes to system configuration, needed infrastructure replacement, upgrades and modernization investments, and potential for non-wires alternatives. The assessment of current system capabilities would be

compared with the forecasts of load and DER deployment (or net load) to identify locations on the distribution system where the forecasted needs of customers will exceed existing capacity and capabilities. At the same time, this analysis can also identify locations where deployment of additional DERs or traditional assets would have the greatest value.

95. We further agree with the proponents that a GNA provides the Commission and stakeholders with critical information needed to better understand the utility's distribution system investments and where NWAs may be suitable. The GNA may identify constraints on the electric grid and infrastructure upgrades and/or DER projects that may provide solutions to those constraints. We note that a fully functional GNA will incorporate results of locational net benefit analyses. We thus encourage the utilities to begin discussions with stakeholders about potential programs or pilots that will conduct a cost benefit analysis of DER that incorporates the location-specific net benefits to the electric grid.

96. Proposed Rule 3532, based on WRA's proposed rule, 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. The utility would present this data in megawatt values in tables, in a logical spreadsheet form and graphically as a map, both of which will be provided over the Web Portal. The GNA would also identify locations where substation transformers and feeders have sufficient capacity for hosting multiple EV fast charging stations.

97. We seek comment on the following question:

- How can a GNA provide valuable information while protecting confidential and secure information?
- Should the utilities provide a description of the process it uses to identify grid needs, including relevant sources for stakeholder evaluation?

i. Rule 3533. Grid Innovation

98. WRA proposed a section on Grid Innovation for utilities to propose or provide updates on pilots and programs related to the integration of new distribution grid technologies which reduce environmental impacts, lower ratepayer costs, improve resiliency, enhance customer experience, efficiently integrate DER, and/or provide other benefits. In order to encourage utility understanding of and experience of new technologies or rates which will enhance the functionality of the distribution grid, WRA recommends the utility be required to file two new pilots with each Distribution System Plan. WRA suggests that within its DSP, the utility may seek approval for a new Program to better integrate DER into its business practices in a way that improves system performance, minimizes costs, increase system resiliency and/or reliability, and/or reduces emissions. WRA adds that such proposed programs may be successors of completed Pilots. WRA also suggests the DSP shall identify any barriers to deployment of DER, including barriers to integration/interconnection of DERs onto the distribution grid, barriers that limit the ability of a DER to provide benefits, and barriers related to distribution system operational and infrastructure capability to enable DER-provided value related to needed investment in advanced technology such as advanced protection and control systems, telecommunications and sensing.

99. We agree with WRA's proposed rules on Grid Innovation and include a version of them as part of Rule 3533. The Proposed Rule 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.

100. We seek comment on the following questions:

- How can the Commission provide a discrete path for third party to propose its own pilot proposals?
- What market or informational barriers might be needed to be identified in the Grid Innovation descriptions?

j. Rule 3534. NWA Cost Benefit Analysis

101. SB 19-236 requires the Commission to develop a methodology for evaluating the costs and net benefits of using DER as non-wires alternatives.

102. WRA's proposed rules do not prescribe a specific methodology, but leave it up to the utilities to develop a methodology with interested stakeholders and have it approved by the Commission. WRA suggests the methodology must meet certain criteria, including the evaluation of the full suite of DER to meet the grid constraint issue, including distributed generation, energy storage, energy efficiency, and demand response. It should also consider using a combination of DERs. WRA states that the utility should consider specific avoided costs from using an NWA in its methodology, including avoided or deferred sub-transmission and substation upgrade costs, avoided feeder capital and operating expenses, avoided distribution voltage and power quality capital and operating expenditures, avoided Greenhouse Gas Emissions (GHG), including monetized benefits at the Commission approved social cost of carbon. Finally, WRA suggests the cost-benefit analysis consider reduced reliability and resiliency costs and other avoided or deferred capital, programmatic, or operational expenses.

103. COSSA/SEIA state that there are various well-established cost-effectiveness tests that can be used to evaluate the impact of DERs. They suggest the Commission ensure that a

broad range of costs and benefits are evaluated with respect to all NWAs, including public health, environmental benefits, and resiliency. In addition, they believe NWA evaluation must account for distribution-level components of avoidable costs and potential benefits. COSSA/SEIA points to the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM)[4] as a potential comprehensive framework for cost-effectiveness assessment of DERs, including energy efficiency, demand response, distributed generation, distributed storage, and building and vehicle electrification. They also point to several states that have engaged in multi stakeholder working groups to developed a cost-benefit framework.

104. The OCC suggests the Commission establish a standard cost-benefit methodology for DSP, as contemplated by other states. The OCC believes a cost-benefit analysis should be conducted on all distribution system investments using, at a minimum, the after-tax Weighted Average Cost of Capital (WACC) of the utility as the discount rate in evaluation scenarios along with any additional discount rates the Commission deems appropriate. The utility should be required to provide project and portfolio analyses to demonstrate that they are making system investments that benefit ratepayers and are in the public interest. In addition, the OCC believes benefits should be more narrowly construed in the DSP context. The focus of benefits should be on costs avoided or deferred. As stated above, the OCC believes the primary benefits accrued to customers through DSP are those of reduced fuel cost, avoided capital investment or deferred capital investment. Benefits such as avoided emissions and other social and environmental outcomes should not be included as they are currently counted in other reporting frameworks, such as resource planning and/or Renewable Energy Standard compliance reports.

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[4] National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. Available

105. Public Service argues that evaluating NWAs should be a comparative exercise, considering Traditional Utility Investments (TUI) to NWA across criteria. Public Service believes that once the DSP plan identifies areas of the distribution system that may require investments to serve new or growing loads, and defines such issues in a level of approximate detail, then the cost, performance, and benefits of a TUI and an NWA solution can be compared. Public Service cautions that the NWA solution is very complex to evaluate. Public Service requests the Commission consider the complexity of the DSP process and potential NWA solutions as it considers how to develop appropriate rules. Public Service believes that flexibility in rules regarding evaluating the costs and net benefits of DER as an NWA will be essential, especially in the first one or two rounds of DSP plans.

106. Proposed Rule 3534, directs the utility to provide an assessment of the proposed NWA solution using the cost-benefit methodology put forward in the 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 cost-benefit methodology if it concludes that the full costs and benefits of the NWA solution are being accounted for. We expect the NWA Cost Benefit Analysis Methodology to evolve over time as more experience is gained with the process of evaluation NWA against TUI, and accordingly, we expect stakeholders to work together to suggest improvements and provide lessons learned.

107. We solicit comments on the following question:

- How should potential intangible or non-quantifiable benefits of NWAs be evaluated within a CBA?

at https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/

k. Rule 3535. Action Plan

108. CEO describes the Action Plan as a culmination of the utility's DSP process and should provide a clear path of next steps that will act as a road map for the utility and the Commission. The Action Plan should include the sequence of events and timelines for each action that will be taken, including the implementation of NWAs identified through the NWA analysis process, the implementation of proposed pilots and programs, and the implementation of Major Distribution Grid Projects that were determined to be the best option to address grid needs.

109. Proposed Rule 3535 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.

l. Rule 3536. NWA Suitability Screening

110. SB 19-236 instructs the Commission to develop a methodology for evaluating the costs and net benefits of using DER as NWA and to determine a threshold for the size of a new distribution project for when a utility must consider implementation of an NWA.

111. Decision No. C19-0957 discussed that some states, such as New York and California, have spent several years trying to develop a market for NWAs. Several other states are attempting to develop a process for utilities to evaluate and implement NWAs. Progress in this area has been slow and difficult for several reasons, including the complexity of trying to match identified distribution upgrade needs to the capabilities and services that DERs could provide. The Decision also noted that NWAs are typically sought to defer capital investment,

which may reduce the utility's opportunity to earn a rate of return and potentially may lead to lost revenue. Contractual and performance assurance issues between utilities and third-party providers also contribute to the complexity and perceived risk of implementing NWAs. New incentives, regulations, and changes in traditional utility business models may be needed to expand NWAs.

112. In its comments in the DSP Stakeholder Outreach Proceeding, WRA offered a threshold defined in terms of dollars. WRA's proposed rules also define all projects which exceed the threshold and require consideration of NWAs as "Major Distribution Grid Projects." WRA adds that any NWA that passes the screening criteria and is determined to be more cost-effective than a traditional utility investment over the ten-year planning process should be implemented. This means that a project planned for one year, two years, ten years, or anywhere in between could be suitable for an NWA, if it is determined to provide net benefits when compared to a traditional utility investment.

113. CEO proposes some alternative language on NWA and transferred the NWA process content into one rule from other areas of WRA's proposed rules, including the role of the NWA coordinator. CEO also proposes moving other information out of the rule, including the details about the contents of the NWA report, which CEO believes is a deliverable that more readily fits within the Contents of a Distribution System Plan section.

114. CEO also argues that funding for NWAs should come from the budget that is normally used to fund distribution system projects, not from DSM or RES budgets, since this is the way the traditional alternative would have been funded. Several other participants agreed with CEO. Keeping these budgets separate will ensure that DSM or RES budgets are not

inadvertently diverted to NWA projects, thereby cutting into DSM or renewable energy programming.

115. The OCC believes that the best way to evaluate NWAs is through pilot programs supported with an *ex ante* cost-benefit analysis and customer education to improve the program's efficacy. Upon conclusion of the pilot program, an *ex post* cost-benefit analysis should be conducted and compared with the ex-ante analysis with any significant discrepancies explained in the DSP reporting process.

116. 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 a NWA may be suitable alternatives to conventional solutions.

117. We solicit comments on the following questions:

- If the Commission grants approval for the implementation of NWAs without Certificate of Public Convenience and Necessity Application's approved in filings such as the DSP, RES plans, TEP or DSM plans, how should the NWA Cost Benefit Analysis Methodology apply, especially with multi-year projects?
- How should the utilities evaluate NWA solutions on the same foundation as traditional solutions such as a tariff change or new incentive?
- How can a portfolio of NWA solutions, be evaluated as compared to a single solution in order to solve the grid need?
- What role can or should performance-based ratemaking have regarding the potential of NWA deferring capital investment?
- If the Commission focuses Rule 3536 on "major distribution grid projects", proposed to be defined as an investment of more than \$2M on the distribution grid or more than \$3M on both the transmission and distribution grids, how can the Commission continue to encourage NWA analysis and inclusion for smaller projects, which may provide a more reasonable starting point?

m. Rule 3537. Approvals and Cost Recovery

118. There is general agreement among the participants in the DSP Stakeholder Outreach Proceeding on rules regarding cost recovery.

119. Public Service comments that rules regarding Cost Recovery for Non-Wires Alternatives should: 1) ensure that NWAs approved in a DSP do not require a CPCN and are presumed to be prudent and reasonable; 2) allow the Commission to require the utility to demonstrate satisfactory compliance with benchmarks or performance metrics in the decision approving an NWA; and 3) clarify that targeted incentive payments used to support NWAs may not be paid for with Renewable Energy Standard Adjustment collections or demand-side management funds.

120. Public Service also argues that NWA proposals from a DSP can be approved in: 1) Demand Side Management planning proceedings; 2) Renewable Energy Standard planning proceedings; 3) an application for a pilot programs or other innovative technology demonstration; or 4) another appropriate regulatory mechanism. Public Service recommends a threshold of $2M for distribution capacity projects and a threshold of $3M for distribution capacity projects which include transmission components. This threshold concurs with WRA's and COSSA's proposed DSP rules. This will insure that all major capacity projects will be required to include the evaluation of NWAs as part of the project development and provide the opportunity to fully consider NWA alternatives to more traditional capital investments. While projects above this threshold would require NWA alternatives to be considered, smaller projects are also strongly encouraged to evaluate NWA options.

121. CEC submits that DSP investments should be subject to the same cost recovery treatment as electric resource planning investments, and there is no need for "special" regulatory

treatment for DSP-related investments. Indeed, regulatory assets should be used only sparingly, and generally limited to circumstances in which the utility has incurred a material change in costs that are unforeseen, extraordinary, and beyond its control. The recovery of DSP investments should not be viewed simply as expense reimbursement. Instead, ratemaking requires that the investments be demonstrated to be prudent, and used and useful to ratepayers. CEC urges the Commission to place priority on upholding the pillars of just and reasonable rates, and maintaining policies to ensure safe and reliable electric service.

122. COSSA/SEIA also recommend establishing an RFP process for NWA procurement that is automatically triggered by meeting a capital project cost threshold, assuming suitability screening criteria are met. COSSA's approach is reflected in its proposed rules when the project cost threshold and screening criteria are met, a neutral NWA Coordinator should carry out the RFP, assess the responses, and make a recommendation

123. AEE recommends the development of a competitive solicitation framework to source DER-based solutions at the lowest cost. This method allows the utilities to find the least-cost, best-fit DER solutions based on market response, and to ensure that the benefits of competition accrue to all customers. Competitive solicitations also provide the utilities with the essential flexibility to target specific locations, sizes, and durations based on the local distribution need, and to expect contracts with creditworthy and reliable counterparties with viable projects. AEE argues such needs-based solicitations would not presuppose the exact technology solution, but instead leverage the competitive market to come forward with solutions based on needs identified by the utility via the distribution system planning process and the implementation of those plans.

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

125. We seek comment on the following question:

- Should the Commission allow targeted incentive payments for an approved Pilot or NWA paid for with funds from the Renewable Energy Standard Adjustment or the utility demand-side management Program?
- How should the Commission evaluate the first DSP and suggest improvements in utility transparency, particularly when evaluating NWA verses traditional utility investments?
- What policy goals under DSP would be best suited for performance incentives?

n. Rule 3538. Security Assessment

126. SB 19-236 includes requirements for utilities to provide a high-level summary of its 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.

127. In addition to rules describing data and data privacy discussed below, 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 current 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 cyber security 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 neutral 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.

128. We seek comment on the following question:

- How should the Commission enable transparency of data while maintaining the security of the utility's infrastructure?

o. Rule 3539. Data Privacy and Confidentiality

129. In Decision No. C19-0957, the Commission acknowledged that Distribution Planning is data intensive and raises privacy and security concerns. The Decision proposed a series of questions to participants to determine is what data should be shared to foster NWAs in a DSP in a way that ensures that sensitive system information, company trade secrets, and individual customer personal identifiable information are protected.

130. WRA's proposed rules expand on the legislative text, requiring utilities to describe locations that frequently experience reliability issues, list major outages over the past three years, and provide their plans to address physical and cyber security issues they have identified.

131. COSSA/SEIA contend that the utility should provide a range of data related to reliability metrics, outages, voltage management, and threat analysis. The utility should also provide a high-level summary of efforts to address cyber and physical security, including any pilots or programs such as microgrids. Data sharing and transparency can improve utility processes like load forecasting, and increase trust and communication between the utility and other stakeholders. Access to data such as hosting capacity can help stakeholders identify where capacity for more DERs exists, as well as where system constraints could be alleviated with solutions such as battery storage or aggregated demand response. This can help improve

reliability and resiliency. Data sharing is essential to enable third parties like DER developers to develop and plan non-traditional solution sets to address grid needs.

132. The OCC believes that the utilities should make available granular interval data (temporal) at the smallest increment collected by customer meters for analysis purposes, upon request, to parties normally approved to receive and view highly confidential material (the Staff of the OCC and PUC). These sets should include anonymized customer data at the individual level as well as aggregated data sets. The OCC argues this data should be labeled highly confidential to ensure appropriate use of the information.

133. Denver comments that sufficient data on the physical and electrical characteristics of the distribution system at the node level are essential to effective DSP. Information is used by third parties to plan for effective DSP participation to propose NWA solutions and target DER deployments. Relevant data on certain grid attributes should be available to interested stakeholders including government entities, regulators, independent power producers, and NWA providers. In its reply comments, Denver adds that certain data access provisions are currently enshrined in the Rules Regulating Electric Utilities, 4 CCR 723-3, Rules 3025 through 3035. However, these rules are insufficient. They do not adequately support DSP and restrict the ability for communities and customers to measure progress towards clean energy targets generally. Access to complete and accurate data provides the foundation for a customer or community to establish and achieve clean energy targets.

134. Public Service states that all information and data provided as a result of the DSP Rules should comply with Commission's Customer Data Access and Privacy Rules. In order to provide interested parties with information about managing reliability and resilience risks to the

distribution system, the utility shall include a high-level, non-confidential discussion of its planning process for addressing cyber and physical security risks.

135. Public Service states, "it is premature to specifically describe what data should be shared and with what parties and stakeholders. Public Service wants to be clear that it will not be allowing direct access to its systems beyond providing the necessary reporting and information that is necessitated by DSP. The DSP process can provide increased transparency while protecting data privacy and security by only making relevant data and information available to the public. Any reporting of data or information of sensitive data will be made anonymous and generic and in compliance with the Commission's Data Privacy Rules.

136. Black Hills adds that the 15/15 requirement exists in Commission Rule 3033(b). The 15/15 requirement means that, at minimum, the aggregated data set – with all customer identifiers removed – contains at least 15 customers and no single customer in the data set comprises more than 15 percent of the total customer data aggregated by customer class. Black Hills submits the 15/15 rule has performed well, since its adoption in 2011, to protect the privacy of customers' data. Black Hills understands the 15/15 rule has a long regulatory history in California and Illinois.

137. We propose Rule 3539 which states that the DSP Application is presumed non-confidential and the Commission's Rules on Customer Data Access and Confidentiality do not apply. The utility shall file a Motion for Extraordinary Protection for any information for which it seeks treatment as confidential or highly confidential, the basis for that claim, and its proposed alternative treatment of the information to allow full and fair public consideration of the Distribution System Plan. We also propose the utility hire a bid monitor for any potential NWA RFP process. The purpose of the bid monitor is to ensure that the utility releases sufficient

information to prospective bidders in order to enable them to produce responses, and to mediate requests for additional information.

138. We seek comment on the following questions:

- Should the Commission require utilities to conduct an analysis to assess the appropriateness of statistical non-disclosure standards for specific metrics?
- Which metrics, if any, of those proposed for inclusion with DSPs and web portals are most likely to create privacy risks or be considered proprietary for market/competitive purposes?

p. Rule 3540. Evaluation and Reporting

139. We propose Rule 3540 that directs the utilities, beginning with its second DSP application, to file a report that describes 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. The report should also describe any lessons learned from the DSP process and identify ways to improve methodologies through research before the next filing.

q. Rule 3541. Commission Approval of a DSP

140. We propose Rule 3541 regarding Commission approval of a DSP, allowing the Commission to 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 pursuant to Rules 3601 and 3635 from investments in the distribution grid and distributed energy resources.

r. Rule 3542. Web Portal

141. In their proposed rules submitted in the DSP Stakeholder Outreach Proceeding, WRA, CEO, and COSSA/SEIA argue for a required Web Portal that will include historic,

current, and forecasted data for grid constraints and hosting capacity. It will allow for numeric data for individual substations, circuits, and feeders to be available by clicking on the map. Users will be able to download the data in a logical, tabular format. The participating utilities will also provide a user guide to explain how to use the Web Portal.

142. Proposed Rule 3542 directs the utility to provide a provide a Web Portal to report the results from the Hosting Capacity Analysis and the Grid Needs Assessment, as well as non-confidential information including summaries, data, and reports related to the distribution system as listed in Rule 3542(f). A Web Portal as prescribed in these rules is intended to foster transparency, clarity, and convenience for the Commission, ratepayers and stakeholders. As Public Service has previously stated in previous proceedings, it has many different policies, programs, requirements, reporting, and data related to the distribution grid. There has not been any effort to provide this large amount of information into one, secure source where Commission Staff, ratepayers and stakeholders can benefit.

143. We seek comment on the following questions:

- How can the Commission reduce reporting requirements while providing necessary data for all stakeholders?

D. Conclusion

144. The statutory authority for the rules proposed here is found at §§ 24-4-101 *et seq.*, and 40-2-132, C.R.S.

145. Prior to our issuance of this NOPR, consistent with § 24-4-103(2), C.R.S., representative groups of participants with an interest in the subject matter of this rulemaking were established, submitted views, and participated informally on the proposal under

consideration. These participants are included on the list of persons who receive notification of the NOPR.

146. The proposed rules in legislative (*i.e.*, strikeout/underline) format (Attachment A) and final format (Attachment B) are available through the Commission's Electronic Filings (E-Filings) System at:

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

147. The Commission will conduct a hearing *en banc* on the proposed rules and related issues March 11 and 12, 2021. This hearing will likely be conducted via Video Conference. The details on how to access the hearing will be provided in a future decision.

148. The Commission encourages interested persons to submit written comments before the hearing scheduled in this matter. In the event interested persons wish to file comments before the hearing, the Commission requests that comments be filed no later than January 29, 2021, that any pre-filed comments responsive to the initial comments be submitted no later than February 19, 2021, and that any changes are proposed in legislative redline format. The Commission prefers that comments be filed using its E-Filings System at https://www.dora.state.co.us/pls/efi/EFI.homepage in this proceeding. The Commission will consider all submissions, whether oral or written.

149. Interested persons may provide oral comments at the public hearing unless the Commission deems oral presentations unnecessary.

II. ORDER

A. The Commission Orders That:

1. This Notice of Proposed Rulemaking including Attachments A and B shall be filed with the Colorado Secretary of State for publication in the December 25, 2020, edition of *The Colorado Register*.

2. A hearing on the proposed rules and related matters shall be held as follows:

DATES: March 11 and 12, 2021

TIME: 9:00 a.m. until not later than 5:00 p.m.

PLACE: By video conference using GoToMeetings at a link that will be provided in a future Decision

3. At the time set for hearing in this matter, interested persons may submit written comments and may present these orally unless the Commission deems oral presentation unnecessary. The Commission prefers and encourages interested persons to pre-file comments in this proceeding through its E-Filings System at:

https://www.dora.state.co.us/pls/efi/EFI.homepage.

4. The Commission requests that initial pre-filed comments be submitted no later than January 29, 2021, and that any pre-filed comments responsive to the initial comments be submitted no later than February 19, 2021. The Commission will consider all submissions, whether oral or written.

5. This Decision is effective upon its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING November 25, 2020.

(S E A L)

ATTEST: A TRUE COPY

Doug Dean,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

JEFFREY P. ACKERMANN

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JOHN GAVAN

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MEGAN M. GILMAN

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Commissioners