ATTACHMENT S: COLORADO PUBLIC UTILITIES COMMISSION DECISION REGARDING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND NOISE AND MAGNETIC FIELD REASONABLENESS FOR COLORADO'S POWER PATHWAY

Decision No. C22-0270

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 21A-0096E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR COLORADO'S POWER PATHWAY 345 KV TRANSMISSION PROJECT AND ASSOCIATED FINDINGS REGARDING NOISE AND MAGNETIC FIELD REASONABLENESS.

**DECISION ADDRESSING APPLICATION,
APPROVING SETTLEMENT AGREEMENT IN PART,
AND DENYING PARTIAL STIPULATION**

Mailed Date:	June 2, 2022
Adopted Dates:	February 11, 2022 and February 23, 2022

TABLE OF CONTENTS

I. BY THE COMMISSION

A. Statement

1. By this Decision, the Public Utilities Commission (Commission or PUC) grants Public Service Company of Colorado (Public Service or Company) a Certificate of Public Convenience and Necessity (CPCN) for Colorado's Power Pathway 345 kilovolt (kV)

Transmission Project (Pathway Project or Project), as described in the Company's Application for the Project filed on March 2, 2021 (Application). This Decision also implements a Performance Incentive Mechanism (PIM) to motivate timely completion of the Pathway Project and discourage imprudent cost overruns.

B. Background

1. Procedural Background

2. On March 2, 2021, Public Service filed its Application with supporting attachments and pre-filed testimony for a CPCN for the Pathway Project, requesting that the Public Utilities Commission: (1) issue a CPCN for the Pathway Project; (2) find that the Pathway Project is reasonable and in the public interest, supported by the Company's cost estimate for the Project; and (3) find that the associated noise and magnetic field levels that the Company estimates will result from the Pathway Project are reasonable and require no further mitigation or prudent avoidance measures.

3. Public Service also proposes that the Commission consider issuing a CPCN for the May Valley-Longhorn Extension (MVL Extension), an approximately 90-mile 345 kV double circuit transmission line from a new substation to be constructed at the southeastern corner of the Pathway Project near Lamar, Colorado, south to a new substation near Vilas, Colorado. If the Commission decides a CPCN should be granted for the MVL Extension, Public Service also requests the Commission find the extension is reasonable and in the public interest, supported by the Company's cost estimate for the extension, and that the associated magnetic field and noise levels are reasonable and require no further mitigation or prudent avoidance measures.

4. The Company filed supporting testimony from seven witnesses:[1] Alice K. Jackson, Brooke A. Trammell, Amanda R. King, James F. Hill, Brian J. Richter, Byron R. Craig, and Carly R. Rowe. Ms. Jackson's testimony described the Pathway Project's role in reducing the Company's emissions and achievement of the Company's energy policy goals. Ms. Trammell's testimony summarizes the Application and Project overview. Mr. Hill's testimony describes the need for the Company's need for the Project as a component of resource planning. Mr. Richter puts forth a cost estimate for the Pathway Project. Mr. Craig describes the engineering plans for the Project as well as sponsors the noise and magnetic field analyses performed. Ms. Rowe discusses the siting, permitting, and land rights activities associated with the Pathway Project.

5. The intervenors to this Proceeding include: Staff of the Public Utilities Commission (Staff), the Colorado Office of the Consumer Utility Advocate (UCA), the Colorado Energy Office (CEO), Holy Cross Electric Association Inc. (Holy Cross), Platte River Power Authority (PRPA), Black Hills Colorado Electric, LLC (BHE), Interwest Energy Alliance (Interwest), Intermountain Rural Electric Association (CORE), County of Pueblo (Pueblo), Colorado Energy Consumers Group (CEC), Tri-State Generation and Transmission Association, Inc. (Tri-State), Colorado Springs Utilities (CSU), Colorado Independent Energy Association (CIEA), Colorado Solar and Storage Association (COSSA), the Solar Energy Industries Association (SEIA), Mr. Larry Miloshevich, the Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO (jointly,

[1] *See* HE 101, Direct Testimony of Alice K. Jackson; HE 102, Direct Testimony of Brooke A. Trammell; HE 103, Direct Testimony of James F. Hill; HE 104, Direct Testimony of Amanda R. King; HE 105, Direct Testimony of Brian J. Richter; HE 106, Direct Testimony of Bryon R. Craig; HE 107, Direct Testimony of Carly R. Rowe.

RMELC/CBCTC), LSP Transmission Holdings II, LLC and Western Energy Connection, LLC (together, LS Power), Western Resource Advocates (WRA), and Climax Molybdenum Company (Climax).[2] Decision No. C21-0314-I set the matter for hearing *en banc*.

6. Decision No. C21-0532-I issued September 1, 2021, extended the deadline for a Commission decision by an additional 130 days, as permitted by § 40-6-109.5(4), C.R.S.

7. Public Service filed Supplemental Direct Testimony on September 3, 2021. On or before September 24, 2021, Answer Testimony was filed by Larry Miloshevich, CEC, Interwest, CEO, COSSA/SEIA, WRA, Pueblo, Tri-State, Staff, UCA, CIEA, LS Power, CORE, Pueblo, and RMELC/CBCTC. Public Service filed Rebuttal Testimony on or around October 22, 2021.

8. On November 9, 2021, Public Service, Staff, CEO, RMELC/CBCTC, COSSA/SEIA, WRA, PRPA, CIEA, Interwest, and Pueblo (collectively, Settling Parties) filed a Motion to Approve Non-unanimous Comprehensive Settlement Agreement and Recommended Hearing Procedures and attached Settlement Agreement (Settlement Agreement). The specific terms of the Settlement Agreement are discussed below.

9. Also on November 9, 2021, UCA, CEC, and Climax (collectively, Stipulating Parties) filed a Joint Motion for Approval of Partial Stipulation and attached the Partial Stipulation Agreement (Partial Stipulation). The specific terms of the Partial Stipulation are discussed below.

10. The Commission held an *en banc* evidentiary hearing on November 15, 16, and 17, 2021. Public Service, Staff, UCA, PRPA, Black Hills, Interwest, CORE, Pueblo, CEO, CEC, Tri-State, Colorado Springs, CIEA, COSSA/SEIA, RMELC/CBCTC, LS Power, WRA, and Climax each entered appearances.

[2] Decision No. C21-0314-I, issued May 27, 2021.

11. Post-hearing statements of position (SOPs) were filed on or before December 10, 2021, by WRA, Interwest, LS Power, Pueblo, Black Hills, Larry Miloshevich, COSSA/SEIA, CEO, UCA, CORE, CIEA, CEC jointly with Climax, and Public Service, jointly with Staff and RMEL/CBCTC.

12. The Commission initiated its deliberations adopting this Decision at a Commissioners' Deliberations Meeting on February 11, 2022. The Commission completed deliberations at the Commissioners' Weekly Meeting on February 23, 2022.

2. The Power Pathway Project

a. Description

13. The Pathway Project consists of approximately 560 miles of 345 kV, double-circuit transmission lines that would connect the Front Range to areas rich in solar and wind potential in northeastern, eastern, and southeastern Colorado. Public Service presents the Power Pathway Project in five segments. The Company proposes that the northern terminus of the Project will be at the existing Fort St. Vrain Substation in western Weld County; that the Project will extend east to a new substation near the existing Pawnee Substation (Segment 1); then east/southeast to a new substation south of the City of Burlington (Segment 2); then south to a new substation northeast of the City of Lamar (Segment 3); then west to the planned Tundra Substation near the Comanche Generating Station (Segment 4); and then north to its terminus at the existing Harvest Mile substation located in Arapahoe County (Segment 5). The Pathway Project also involves expansion of the existing Fort St. Vrain, Pawnee, and Harvest Mile Substations, expansion of the planned Tundra Substation and construction of three new substations.

14. The proposed May Valley-Longhorn Extension consists of approximately 90 miles of 345 kV double circuit transmission line from a new substation to be constructed at the southeastern corner of the Pathway Project near Lamar, Colorado, south to a new substation near Vilas, Colorado.

15. The Company proposes that each segment of transmission line will be constructed using single pole, double circuit tangent structures and two-pole dead-end structures, with two-bundle 1272 kcmil ACSR Bittern conductors. It asserts that undergrounding the Project would not be reasonable because it would be cost-prohibitive, and because of technical issues involved with significantly higher reactive power produced by alternating current (AC) underground cables.[3] Public Service states that as proposed, the Pathway Project will be able to reliably carry the coincident injection of approximately 3,000 to 3,500 MW of electric power from new generation, and that the Project will be able to accommodate a nameplate generation capacity higher than these figures.[4]

16. The Company asserts that the Pathway Project will provide a "backbone network transmission system" in eastern Colorado.[5] It explains that the Project will consist of bulk transmission lines networked together, so that there is more than one path to deliver electricity from generation to load, and that the proposed looped configuration with multiple electricity pathways inherently provides greater system reliability and operational benefits than radial transmission or long gen-ties.[6] It states that the Pathway Project would "significantly improve

[3] HE 104, Direct Testimony of Amanda R. King, at 77:4-78:2.
[4] HE 104, Direct Testimony of Amanda R. King, at 38:2-9.
[5] HE 102, Direct Testimony of Brooke A. Trammell, at 16:7-13.
[6] HE 104, Direct Testimony of Amanda R. King, at 26:20-28:2.

reliability of the Colorado transmission network"[7] as high levels of variable energy resources are brought on to the system and the dependency on variable resources to meet system reliability increases.[8]

17. The Company explains that pursuant to Senate Bill (SB) 19-236, it is required to file a 2021 Electric Resource Plan (ERP) and Clean Energy Plan (CEP) that achieves an 80 percent carbon dioxide emission reduction from 2005 levels by 2030.[9] Company witness Mr. Hill states that as part of achieving this level of emissions reduction in its 2021 ERP and CEP, the Company anticipates it will add roughly 2,300 MW of utility-scale wind, 1,600 MW of utility-scale solar, and 400 MW of storage.[10] Public Service also notes that SB 19-236 establishes a target for the Company of 100 percent emission reduction by 2050, and that House Bill (HB) 19-1261 establishes additional economywide goals for Colorado.[11]Company witness Ms. Trammell explains that through the requirements of SB07-100, it has designated five Energy Resource Zones (ERZs)[12], largely located in eastern and southern Colorado, in which there are significant wind and solar resources that have seen minimal development. Public Service explains that currently there is very limited transmission available in eastern Colorado, which would leave generators to develop long, costly, and unreliable radial or gen-tie lines to

[7] HE 104, Direct Testimony of Amanda R. King, at 52:5-8.

[8] HE 101, Direct Testimony of Alice K. Jackson, at 36:4-6.

[9] The Company filed its 2021 ERP & CEP Application on March 31, 2021 in Proceeding No. 21A-0141E (2021 ERP & CEP).

[10] HE 103 Direct Testimony of James F. Hill, at p. 19; HE 108, Supplemental Direct Testimony of Brooke A. Trammell, at p.8.

[11] HB 19-1261, codified at § 25-7-102(g), C.R.S., establishes economywide greenhouse gas emission reduction goals based on a 2005 emission baseline of: 26 percent reduction by 2025; 50 percent reduction by 2030; and 90 percent reduction by 2050.

[12] SB07-100, codified at § 40-2-126, C.R.S., defines ERZs as "geographic area[s] in which transmission constraints hinder the delivery of electricity to Colorado customers, the development of new electric generation facilities to serve Colorado consumers, or both."

interconnect renewable resources in these areas to the existing transmission network.[13] Public Service contends that adding a transmission backbone in eastern Colorado through approval of the Pathway Project will unlock clean energy resources in Colorado's designated ERZs 1, 2, 3, and 5 necessary to meet the 2030 clean energy target of SB19-236. Without an expanded transmission system capable of integrating the significant amount of new clean energy resources necessary to meet emission reduction goals, the Company states, it will be unable to meet its statutory requirements in 2030. The Company also asserts that the Project will "form the bedrock for future development" necessary to meet emission reduction goals beyond 2030.[14]

18. To support the proposed MVL Extension, the Company states the extension would establish additional transmission infrastructure to support the interconnection of resources in southeastern Colorado, an area rich in wind resources. Public Service asserts that "having a well-planned transmission line to this area" would also minimize developers' need to construct multiple, costly generation tie lines to interconnect to the Pathway Project.[15]

19. As explained by Company witness Mr. Richter, Public Service plans to construct the Project in three major phases. It expects that Segments 2 and 3 will be placed in service by the end of 2025. Segment 1 is planned to be in service by the end of 2026. The Company expects that Segments 4 and 5 will be in service by the end of 2027.

20. Public Service explains that Segments 2 and 3 will bring transmission infrastructure to wind-rich regions in eastern Colorado, and that adding new renewable generation by the end of 2025 supports the state's greenhouse gas emissions reduction target

[13] HE 104, Direct Testimony of Amanda R. King, at 29:2-30:2.
[14] HE 104, Direct Testimony of Amanda R. King, at 26:13-17.
[15] HE 102, Direct Testimony of Brooke A. Trammell, at 19:8-13.

timelines.[16] Additionally, the Company asserts that by having these segments in-service by the end of 2025, wind and solar developers will be able to interconnect resources prior to the expiration of the Production Tax Credit (PTC) and step down of the Investment Tax Credit (ITC),[17] which would represent cost savings of approximately $300 million per GW of interconnected wind capacity and $100 million per GW of interconnected solar capacity, in net present value, to customers. The Company states that Segments 1, 4, and 5 will provide improved reliability.[18]

21. Additionally, Public Service explains that it is proposing the Pathway Project in advance of the approval of its 2021 ERP and CEP to provide a strategic backbone transmission resource in eastern Colorado, so that bidders may propose to interconnect to the Project during the Phase II competitive solicitation. The Company explains this would remove some uncertainty for renewable developers in where they may interconnect their projects, in turn reducing the potential bid prices made in the competitive solicitation. It states that waiting to design and construct transmission until after the acquisition of renewable generation would create a timing dilemma between resource and transmission planning, which is made more acute by impending emission reduction targets - if the transmission facilities are not identified until after the Commission approves the development or acquisition of renewable resources, the transmission lines may not be constructed by the time the new generation resources are ready to be placed in service and necessary to meet emission reduction targets.[19] Further, the Company contends that approval of the Pathway Project to accommodate future anticipated generation development is

[16] HE 104, Direct Testimony of Amanda R. King, at 20:4-21:6.

[17] HE 104, Direct Testimony of Amanda R. King, at 20:4-9; Hearing Exhibit 110, Supplemental Direct Testimony of James F. Hill, p.10.

[18] HE 104, Direct Testimony of Amanda R. King, at 21:12-13.

[19] HE 102, Direct Testimony of Brooke A. Trammell, at 31:3-32:2.

consistent with the intent of SB07-100 and with the reasoning in prior CPCN approvals such as those in Decision No. C11-0288, issued March 23 2011 in consolidated Proceeding Nos. 09A-324E and 09A-325E, and Decision No. R14-1405, issued November 25, 2014 in Proceeding No. 14A-0287E.

b. Cost Estimates

22. In accordance with Rule 3102(b)(IV), 4 *Code of Colorado Regulations* (CCR) 723-3 of the Commission's Rules Regulating Electric Utilities, Public Service included estimated costs of the proposed Project itemized as land costs, substation costs, and transmission line costs.[20] The overall cost estimate for the Pathway Project presented by the Company is approximately $1.695 billion and $247 million for the MVL Extension. Of that overall cost estimate, the Company anticipates the transmission line costs to total $1.379 billion, of which $121 million is attributed to land costs. The Company anticipates substation costs to total $316 million, of which $122 million is associated with land costs.[21] While the Company chose not to present a contingency range for the Pathway Project cost estimates, it does include risk reserve amounts for anticipated risks.

c. Project Alternatives

23. Public Service explains that it evaluated alternatives to the Pathway Project through the stakeholder process of the Colorado Coordinated Planning Group 80x30 Task Force (CCPG 80x30 TF).[22] The CCPG, a joint high-voltage transmission planning forum that is a

[20] *See* HE 105, Direct Testimony of Brian J. Richter and attachments RJR 1-5; HE 115 Rebuttal Testimony of Brian J. Richter.

[21] Application, at ¶¶ 7-9; HE 105, Direct Testimony of Brian J. Richter, at 32:11.

[22] Application, at ¶ 7.

subregional planning group under the WestConnect planning region,[23] launched the 80x30 TF in August 2020 to provide a platform for stakeholders to collaboratively identify transmission infrastructure that will enable utilities to meet Colorado's emission reduction goals.[24]

24. The CCPG 80x30 TF performed transmission steady state power flow studies that modeled a benchmark case and a series of transmission-build alternatives, each with the assumption that 3,000 MW of new renewable generation and 3,000 MW of existing renewable generation would need to be simultaneously dispatched on Public Service's system to meet the 80 percent emissions reduction target by 2030 and the Company's projected 2030 peak summer load.[25] In the benchmark case, generation was added at locations available on the existing system, including planned additions through 2030. Public Service explains that this benchmark case shows the existing transmission system is "full," such that the existing system will not be able to reliably serve new generation in ERZs 1, 2, 3, and 5, which would endanger the Company's ability to achieve its clean energy target for 2030 under SB19-236.[26] The Company also asserts that adding more renewable generation to its system without transmission infrastructure to access eastern Colorado would most likely burden Public Service's customers with extra costs in the long run, because developers would be forced to develop very long gen-ties or locate renewable resources in areas around existing transmission that have inferior renewable sources.[27]

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[23] HE 104, Direct Testimony of Amanda R. King, at 41:15-41:20.

[24] *Id*. at 41:08-41:14.

[25] *Id*. at 42:21-43:17; 47:1-49:2.

[26] HE 101, Direct Testimony of Alice K. Jackson, at 41:1-42:10; HE 104, Direct Testimony of Amanda R. King, at 51:18-14.

[27] HE 104, Direct Testimony of Amanda R. King, at 71:20-72:2.

25. The CCPG 80X30 TF studied six transmission-build alternatives in addition to the Pathway Project. For each option, the study models assumed that the majority of the 3,000 MW output from new generation would be injected at various substations, based on expected locations for new renewable generation. The Company explains that the alternatives were not pursued due to: the failure to facilitate increase generation access in all of ERZs 1, 2, 3, and 5; reliability concerns; higher reactive power requirements than the chosen alternative; or requiring greater substation interconnects than the chosen Pathway Project.[28] Thus, according to the Company, the Pathway Project "emerged as the top performer" because it provided the overall best study results from a reliability and resource diversity perspective and was identified to have the greatest and most cost-effective injection and transfer capacity, with opportunities for future expansion.[29]

3. Nonunanimous Comprehensive Settlement Agreement

26. The Settling Parties filed a Motion for Approval of the Settlement Agreement on November 9, 2021. The Settlement Agreement resolves all material issues as identified by the Settling Parties, including that:

a) The Company has met its burden of proof and so the Commission should approve a CPCN for the Pathway Project (Segments 1 – 5);[30]

b) The Company has presented adequate cost information in support of its $1.695 billion cost estimate for the Pathway Project as well as the MVL Extension;

c) The construction sequencing and timeline presented by the Company is reasonable and in the public interest;[31]

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[28] Application at ¶ 17.

[29] HE 104, Direct Testimony of Amanda R. King, at 70:26-71:10.

[30] Hr. Ex. 119, Non-Unanimous Comprehensive Settlement Agreement (filed Nov. 9, 2021) (Settlement Agreement), at ¶¶ 1-2.

[31] Settlement Agreement, at ¶ 5.

d) Recovery of the Pathway Project costs through the Transmission Cost Adjustment (TCA) is appropriate and no presumption of prudence will attach to the cost estimates for the Pathway Project;[32]

e) The Settlement Parties agree on design of an appropriate PIM, reflected in Appendix 1 to the Settlement Agreement;[33]

f) The expected maximum magnetic field and noise levels associated with the Pathway Project are reasonable and require no further mitigation or prudent avoidance measures;[34]

g) Public Service will present as part of any future transmission CPCN applications associated with the 2021 ERP and CEP follow-on transmission investment, a detailed explanation of Advanced Transmission Technologies (ATTs) considered for any project;[35]

h) The Commission should grant a conditional approval and finding of need for the MVL Extension in the final approved resource plan in Proceeding No. 21A-0141E. The Settling Parties established modeling parameters for the MVL Extension, and agreed on the $247 million cost estimate for the MVL Extension, and as well as on specific PIM, noise and magnetic field levels, and future cost recovery terms for the MVL Extension;[36]

i) Semi-annual reports will be filed within this Proceeding detailing, among other information, actual Project expenses, modifications to forecasted expenditures, explanation of any material changes to cost and installation schedule, and overall Project schedule and status;[37]

j) The Commission should delay determination of any issues associated with statutory interpretation of § 40-2-125.5(5), C.R.S., and the scope of the "clean energy plan revenue rider" until Proceeding No. 21A-0141E;[38]

k) The Commission should open a miscellaneous proceeding to solicit further comments and study on transmission solutions into and out of the San Luis Valley;[39]

l) The Commission should adopt specific language related to the prohibitory cost of undergrounding transmission lines of the Pathway Project;[40] and

m) While Public Service does not anticipate a joint ownership/partnership for the Pathway Project at this time, if such an arrangement materializes in the future,

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[32] Settlement Agreement, at ¶ 6.

[33] Settlement Agreement, at ¶¶ 7-14.

[34] Settlement Agreement, at ¶ 15.

[35] Settlement Agreement, at ¶ 16.

[36] Settlement Agreement, at ¶¶ 17-24.

[37] Settlement Agreement, at ¶¶ 25-27.

[38] Settlement Agreement, at ¶ 28.

[39] Settlement Agreement, at ¶ 29.

[40] Settlement Agreement, at ¶ 30.

Public Service will make the appropriate filing(s) with for Commission review and approval.[41]

4. Partial Stipulation

27. The Stipulating Parties filed a Motion for Approval of Partial Stipulation on November 9, 2021. The Stipulating Parties agree the Commission should:

a) Grant a CPCN limited to Segment 2[42] and the proposed expanded or newly built substation facilities at Pawnee, Canal Crossing, and Goose Creek;[43]

b) Grant a conditional CPCN for Segments 1, 3, 4, and 5 and the associated substations as part of or following the Phase II of Public Service's 2021 and 2022 CEP & ERP proceeding, if the Commission approves a final CEP with a minimum total nameplate capacity of 2,925 MW (75% of the Company's estimate of Power Pathway-interconnected resources it expects to acquire via the ongoing ERP & CEP proceeding) committed to interconnect to the Project;[44]

c) Consider additional conditions on the CPCN to promote opportunities for cost-effective planning and construction activities, including coordinated regional transmission planning and competitive bidding;[45]

d) Grant a conditional approval and finding of need for the MVL Extension in this Proceeding, subject to a conditional approval of Segment 3 and inclusion of the MVL Extension in the Company's final approved 2021 CEP and ERP;[46] and

e) Hold the Company to a performance plan under which the Company's provided Project budget, including risk reserve and all categories of construction and planning costs, would be utilized as the PIM target and not subject to adjustments in future proceedings; 10% of cost savings relative to the Project budget would be returned to shareholders, and 90% returned to ratepayers.[47]

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[41] Settlement Agreement, at ¶ 31.

[42] The Partial Stipulation defines the Segment 2 portion of the Pathway Project: "Segment 2 would create a new 345 kV transmission loop running from Pawnee Substation east to near Yuma, Colorado, then south-southeast to Goose Creek Substation, and then back west to Missile Site Substation using the existing Rush Creek Gen-Tie." Joint Stipulation, p.3, fn. 2.

[43] Hr. Ex. 1103, Partial Stipulation (filed Nov. 9, 2021) (Partial Stipulation), at ¶ 1.

[44] Partial Stipulation, at ¶¶ 4-6.

[45] Partial Stipulation, at ¶ 7.

[46] Partial Stipulation, at ¶ 10.

[47] Partial Stipulation, at ¶¶ 11-12.

5. Hearings and Evidentiary Record

28. At the evidentiary hearing on November 15 through 17, 2021, the Commission admitted the documents listed on Hearing Exhibit (HE) 2100 into evidence which represented all prefiled testimony in the Proceeding. HEs 1702, 1703, 1402, 1403, 1404, 1405, 1406, 1407, 1408, 1409, 1410, 1411, 100, 113, 119, 1902, 323, 324, 314, 304, 316, 1102, 115, 1400-Rev. 1, 1400.17, 1103, 1401, 1415, 1418, and 1419 were offered and admitted into the record during the evidentiary hearing. At hearing, the Commission took also administrative notice of HEs 325, 321, 317, 322, 318, and 1412. In addition, the administrative record for this Proceeding includes numerous written public comments.

29. No party provided written testimony in support of the Settlement Agreement or the Partial Stipulation. At the Hearing, Company witnesses Ms. Brooke Trammell, Ms. Amanda King, Mr. Liam Noialles, and Mr. Byron Craig testified. Ms. Brooke Trammell and Mr. Gene Camp of Staff also provided live direct testimony in support of the Settlement Agreement.[48]Mr. James Dauphinais, Mr. Christopher Clack, Mr. Chris Neil, and Dr. Scott England testified on behalf of UCA. Mr. James Dauphinais additionally provided live direct testimony in support of the Partial Stipulation. In addition, Ms. Sharon Segner testified on behalf of LS Power.

[48] In response to Notices filed by Climax and UCA on November 12 and November 15, 2021 respectively, which informed the Commission of their intent to provide live testimony in support of the Partial Stipulation, the Commission ordered the Settling Parties to provide up to two witnesses to support the Settlement Agreement with live direct examination and the Stipulating Parties to provide up to one witness to support the Partial Stipulation with live direct examination.

6. Party Positions[49]

a. Settling Parties

30. Generally, the Settling Parties contend that the record supports the need for the Pathway Project and that without the Project, Public Service will be unable to achieve the emission reduction targets mandated by SB 19-236.[50] Several of the Settling Parties assert that in contrast to the historical approach of building transmission following a decision to build a generating resource, new transmission capacity is now needed in advance of the renewable generation that would utilize it.[51] The Settling Parties argue that approval of the full Pathway Project will provide developers certainty in Public Service's competitive solicitation in the 2021 ERP and CEP, increasing competition and resulting in lower-cost bids.[52] They also assert the Pathway Project will provide additional benefits beyond positioning Public Service to meet emission reduction targets, including enabling optimal access to federal tax credits, improved reliability and resilience, reduced production costs, reduced curtailment, increased import and export capacity, improved voltage stability, reduced need for power purchases, reduced line losses, provision of ancillary services, reduced need for reserve capacity, and increased diversity of resources on Public Service's system.[53]

31. The Settling Parties raise various concerns with the terms expressed in the Partial Stipulation. Several of the Settling Parties contend the "piecemeal approach" to granting CPCNs

[49] In light of the filed Settlement Agreement and the filed Partial Stipulation, we focus on the positions of the parties presented at the evidentiary hearing and in their SOPs.

[50] CEO SOP, pp. 5-10; Interwest SOP, p. 11; Public Service, Trial Staff and RMELC/CBCTC Joint SOP, pp. 3, 5-9; WRA SOP pp. 4-6; COSSA SEIA SOP, pp. 1-3.

[51] Interwest SOP, pp. 16-17; Trial Staff and RMELC/CBCTC Joint SOP, pp. 4, 9.

[52] CIEA SOP, pp. 9-10, 12-14; COSSA/SEIA SOP, pp.3-4; Public Service, Trial Staff, and RMELC/CBCTC Joint SOP, pp. 4, 6, 11, 20.

[53] Interwest SOP, pp. 3-6, 12-14; Public Service, Trial Staff, and RMELC/CBCTC Joint SOP, pp. 5-9; CEO SOP, p. 17; WRA SOP pp. 5-9; CIEA SOP, pp. 14-16; COSSA/SEIA SOP, pp. 3-4.

advocated for in the Partial Stipulation is "inconsistent with prudent transmission planning process[es] and principles."[54] They note that granting a CPCN for Segments 1, 3, 4, and 5 on a contingent basis would increase costs, prevent the Company from optimizing potential federal tax credits, and lessen certainty for bidders in Phase II of the Company's 2021 CEP and ERP.[55] Many Settling Parties also argue that the Partial Stipulation's partial approach would ignore the significant reliability benefits of the Project's looped design, and that the Stipulating Parties inappropriately focus on a 2025 time horizon rather than 2030 and beyond.[56] Settling Parties call the additional competitive planning and bidding provisions in the Partial Stipulation "unworkable" and "vague." They note that the Project is local in scope, incorporated the appropriate planning processes, and in compliance with the Company's OATT.[57]

32. Several parties noted support for a Settlement Agreement PIM within their SOPs. The Company, Staff, and RMELC/CBCTC jointly assert that the PIM proposed in the Settlement Agreement is reasonable and well supported by the record, and that no party has contested the Company's cost estimates. They claim that ratepayers are protected since the Company is not requesting a presumption of prudence in this proceeding and all costs will be subject to a future prudence review. They contend it is reasonable to exclude siting, land rights costs, and material costs from the PIM since these are out of the Company's control.[58] CEO also supports the exclusion of land-related, materials, and environmental compliance costs from the PIM. It states that consumer safeguards remain in place if the Commission adopts the Settlement Agreement

[54] Public Service SOP, p. 16.
[55] *Id*. at 17-18.
[56] Public Service SOP, p. 18; WRA SOP, pp. 19-21.
[57] *Id*. at pp. 22-27.
[58] Public Service Joint SOP, pp. 9-13.

PIM because the Company is not requesting a presumption of prudence.[59] WRA is supportive of the PIM provided for in the Settlement Agreement, but suggests that if the Commission modifies it, it should retain the exclusion of environmental compliance costs from the PIM calculation. WRA notes that it is very difficult to quantify at this time, impacts from the environmental permitting challenges the Company may face in developing the Power Pathway Project. WRA contends that excluding environmental compliance costs from any revisions to the PIM will remove any financial incentive or disincentive the Company could have related to environmental compliance. WRA also states that going too far in creating risks for the Company could "chill the appetite for the project."[60]

33. Additionally, in light of comments made by the Commissioners at the evidentiary hearing , the Company, Staff, and RMEL/CBCTC reiterate support of the PIM as presented in the Settlement Agreement, but offer the Commission the option of a modified PIM that would provide greater incentive for on-time performance.[61] They state that increasing the 2025 return on equity (ROE) adjustment by 75 basis points compared to the original Settlement Agreement PIM proposal would create a larger financial incentive for the company to perform in a timely manner and would continue to "adhere to the overarching policy and legal objectives that a PIM should adhere to."[62]

34. The Company, Staff, and RMELC/CBCTC argue in their Joint SOP that the Company has a statutory right pursuant to § 40-5-101(4)(a), C.R.S., to recover prudently incurred costs and that the Partial Stipulation PIM might prevent this if costs exceed the budget

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[59] CEO SOP p. 19.
[60] Statement of Position of Western Resource Advocates (WRA SOP), p. 16.
[61] Public Service Joint SOP, at pp. 14-15.
[62] *Id*.

cap established by the Stipulation PIM. They contend that the Stipulation PIM violates principles of an appropriate PIM in that it: 1) does not reflect whether an intended goal is being met; 2) does not define how any savings would be distributed to customers or shareholders or over what time period; and 3) would hold the Company responsible for cost categories beyond its control. They also contend that the Partial Stipulation is internally inconsistent, because it fails to present how the PIM would interact with the delays and additional costs its proposed coordinated regional planning process and competitive bidding process would impose.[63]

35. Public Service, RMEL/CBCTC, and Staff raise several concerns with the terms expressed in the Partial Stipulation. They contend the "piecemeal approach" to granting CPCNs advocated for in the Partial Stipulation is "inconsistent with prudent transmission planning process[es] and principles."[64] They note that approving the CPCNs for Segments 1, 3, 4, and 5 on a contingent basis would increase costs, prevent the Company from optimizing potential federal tax credits, and lessen certainty for bidders in Phase II of the Company's 2021 CEP and ERP. The Partial Stipulation's "partial approach" would also ignore the significant reliability benefits of the Project's looped design. The Settling Parties also call the additional competitive planning and bidding provisions in the Partial Stipulation "unworkable" and "vague." They note that the Project is local in scope, incorporated the appropriate planning processes, and complies with the Company's OATT.

36. Public Service, RMEL/CBCTC, and Staff also put forward a joint recommendation concerning the concept of an "Owner's Engineer" discussed by Chairman Eric Blank during the evidentiary hearing. Staff and Public Service suggest that the

[63] *Id*., pp. 20-21.
[64] *Id.,* p. 16.

Commission direct them to work together collaboratively to develop an appropriate scope of work and approach to retaining a third party for the Pathway Project oversight. Staff and Public Service commit to updating the Commission on their progress through a notice filing or status update within 90 days of a final written decision in this Proceeding.

37. Prior to agreement between the Settling Parties, Staff witness Mr. Camp argued that the rate impact cap established by § 40-2-125.5(5), C.R.S., is implicated in this Proceeding because the Pathway Project is a component of Public Service's 2021 CEP and is thus a "clean energy plan activity." A Joint Brief filed by Public Service and other parties disagreed with this position. As previously noted in this Decision, Staff is a signatory to the Settlement Agreement, which defers interpretation of § 40-2-125.5(5), C.R.S., to Proceeding No. 21A-0141E, the proceeding concerning Public Service's 2021 ERP and CEP. Additionally, Staff witness Mr. Gene Camp explained at Hearing that Staff had previously recommended obtaining cost estimates for using alternative conductors for the Pathway Project, and that it had withdrawn this recommendation.

38. Pueblo filed an SOP to reiterate its' support of the Settlement Agreement, despite initial opposition to the Project. Pueblo specifically supports the language regarding undergrounding of the transmission lines in paragraph 30 of the Settlement Agreement and the proposed sole ownership of the Project by Public Service.[65] Pueblo takes no position regarding the position of the transmission lines with respect to siting or permitting.[66]

39. Black Hills originally did not oppose the Settlement Agreement but was not a signatory to it.[67] However, Black Hills stated within its SOP that it supports the Settlement

[65] Pueblo County SOP at p. 2.

[66] Pueblo County SOP, at p. 3.

[67] Joint Motion to Approve Non-unanimous Comprehensive Settlement Agreement, p. 3.

Agreement because it does not preclude Public Service from continuing to consider and assess opportunities for partnership arrangements for the Pathway Project and because it defers interpretation of § 40-2-125.5(5), C.R.S., to Proceeding No. 21A-0141E.[68]

40. PRPA is a party to the Settlement Agreement but did not file an SOP or provide testimony supporting the Settlement Agreement. Additionally, the Settling Parties assert that Tri-State and CSU, which did not file SOPs, are not signatories to the Settlement Agreement but also do not oppose the Settlement.

b. Stipulating Parties

41. The Stipulating Parties argue that Public Service and the Settling Parties have not sufficiently demonstrated the need for the Pathway Project, apart from Segment 2. They contend that Segments 1, 3, 4, and 5 will provide "almost no incremental benefit through 2027 in terms of power-transfer capability and accessing federal tax credits assuming that Segment 2 is completed on time."[69] They argue that granting a CPCN for Segments 1, 3, 4, and 5 now would risk binding ratepayers to costly transmission investment that may not be needed at this time, and would foreclose opportunities to explore more economical alternatives such as competitive bidding or additional regional planning.[70] Thus, the Stipulating Parties urge the Commission to condition approval of Segments 1, 3, 4, and 5 on a showing of need in Phase II of the 2021 ERP and CEP, specifically the Commission's approval of a final CEP with a minimum total nameplate capacity of 2,925 MW. They urge the Commission to condition approval of the MVL Extension on the approval of Segment 3 and the inclusion of the MVL Extension in the approved resource plan in the 2021 ERP and CEP.

[68] Black Hills SOP, pp. 3-5.
[69] UCA SOP, at p. 9.
[70] CEC and Climax SOP, at p. 8.

42. The Stipulating Parties also suggest an alternative PIM structure to addresses comments made by the Commissioners at the evidentiary hearing.[71] They propose that the Commission should derive a PIM that includes "all Power Pathway costs in any PIM, but it could adjust how certain costs are treated," acknowledging that certain costs are less in the Company's control than others.[72] The Stipulating Parties also urge the Commission to include a cost cap as an incentive to the Company and a protection for ratepayers, but note the cost cap could apply in different ways across different categories of costs.[73] Finally, they urge the Commission to include strong incentives for the Company to meet in-service dates and that the "Company should pay for all excess costs to customers for any lost tax credit benefits."[74]

43. The Stipulating Parties contend that their proposed PIM protects consumers better than the Settlement Agreement PIM by imposing a total budget cap that applies to all cost categories and providing an incentive for the Company to meet the critical 2025 deadline in service dates.[75] They argue that the PIM proposed in the Settlement Agreement is too weak to ensure budgetary discipline or adherence to in-service dates, and note that in some scenarios the shareholder return on cost overruns could significantly exceed the proposed penalty. They contend that Settlement Agreement PIM is unfair to ratepayers in that it places only 2 percent of the risk of cost overruns on the Company.[76] The Stipulating Parties note that the PIM proposed in the Settlement Agreement does not contain a cost cap, which they argue is warranted given the

[71] UCA SOP, at pp. 5, 6, and 22.

[72] UCA SOP, at p. 22.

[73] *Id*.

[74] *Id*. at 24.

[75] CEC and Climax SOP, pp. 13-14; UCA SOP, pp. 21-22.

[76] CEC's and Climax's Post-Hearing SOP, at pp. 14-18; UCA SOP, at pp. 15-22; Hg. Tr. Day 2, at 50:8-52:25 (testimony of Staff witness Gene Camp).

proposed $363 million risk reserve.[77] They contend further that the Company actually has at least some control over the cost categories that are excluded from the Settlement Agreement PIM, and that it is therefore unfair to ascribe all risks in these categories to ratepayers.[78]

44. The Stipulating Parties note further that the PIM proposed in the Settlement Agreement provides no penalty for failure to put Segments 2 and 3 into service by 2025 if costs in included categories are less than 105 percent of the budget. Even if they exceed that amount, the penalty pales in comparison to the value of lost tax credits, estimated at a net present value of $300 million per GW for new wind resources.[79]

45. The UCA also notes that the risk reserve contains the Company's estimates of the costs of the risks it anticipates and is ample to account for inflation and higher costs of materials and labor. UCA notes further that the risk reserve includes a significant number of entries labeled "unknown risks" that have a probability of 100 percent of occurrence. It contends that these "unknown risks" are in fact similar to what has been labeled "contingency" in other proceedings. UCA argues that the Company should be held to its estimates, just as independent power producers would be.[80]

c. Other Parties

46. Holy Cross is not party to the Settlement Agreement or the Partial Stipulation. It did not file an SOP or present any testimony.

47. LS Power, in its SOP, urges the Commission to consider competitive transmission procurement prior to approving the Pathway Project because competition will result in

[77] UCA SOP, at pp. 11-12.
[78] CEC's and Climax's Post-Hearing SOP, pp. 5, 17-18; UCA SOP, at pp. 9-11.
[79] CEC's and Climax's Post-Hearing SOP, p. 19; UCA SOP, at pp. 16-18.
[80] UCA SOP, at pp. 13-14.

substantial cost savings and cost certainty for ratepayers.[81] LS Power contends the Commission should deny both the Settlement Agreement and Public Service's Application because the Pathway Project is a regional project and was not planned through existing regional planning processes "as required by FERC Order No. 1000."[82] More specifically, LS Power suggests that the Commission grant a CPCN for only as much transmission as is necessary to enable bidders to access federal tax credits and that additional transmission capacity be procured through other avenues, such as competitive procurement.[83]

48. In its SOP, CORE requests the Commission condition any approval of the Power Pathway on the requirement that the Company "engage in good-faith negotiations with interested utilities that serve Colorado electric customers and are willing and able to invest in joint ownership of the Power Pathway."[84] CORE asserts the Commission should consider including parameters "such as a timeline for study and negotiations, a notification and/or qualification requirement for interested utilities, appointment of Commission Staff or another third-party neutral monitor, and future reporting requirements for the Company and interested utilities" when approving a CPCN for the Pathway Project.[85]

49. Mr. Miloshevich contends in his SOP that only some new transmission is needed to access the best renewable resources. He argues that the combination of existing injection capacity, the opportunity to obtain additional injection capacity through the application of ATTs, and increased local distribution-connected generation and DSM procured via the ongoing

[81] SOP of LSP Transmission Holdings II, LLC and Western Energy Connections, LLC, at pp. 5-12.
[82] LS Power, SOP, at p. 13.
[83] LS Power SOP, at pp. 2-5.
[84] CORE SOP, at p. 2.
[85] CORE SOP, at p. 8.

2021 ERP and CEP proceeding would reduce the need for additional transmission injection capacity requested by Public Service.[86] Mr. Miloshevich also addresses carbon-core conductor technology and suggests additions to the terms of the Settlement Agreement which would "advance the adoption of [] lower-cost modern technologies."[87] He suggests the Settlement Agreement provisions addressing ATTs be replaced by a requirement that Public Service evaluate ATT opportunities for all future CPCNs, evaluate carbon-core conductor for the Power Pathway Project specifically, adjust the PIM to incentivize ATT deployment, and require the Company conduct a formal study of ATTs on the Public Service system.[88] He argues that inertia, misaligned financial incentives, and an entrenched transmission planning process are barriers to utility adoption of ATT, and that it therefore falls to the Commission to require consideration of alternative transmission solutions.

50. While acknowledging flaws in his analysis of the savings potential of carbon-core conductors that were detailed by Company witness Byron Craig, Mr. Miloshevich takes issue with certain aspects of Mr. Craig's analysis, specifically that Mr. Craig chose an inappropriate type of carbon-core conductor (CTC Global instead of TS Conductor), and that choice results in excessive incremental costs for carbon-core conductors relative to ACSR as well as inflation of installation costs by 15 percent.[89] Additionally, he contends that Mr. Craig used an inaccurately low $/MWh value for energy saved through reduced line losses and then discounts those future savings using the Company's weighted average cost of capital, which Mr. Miloshevich contends is inappropriate for costs that are passed through to customers via the ECA, and finally that in

[86] Miloshevich SOP, at pp. 4-5, 16-17.
[87] *Id.* at p. 6.
[88] Miloshevich SOP, at pp. 6-8.
[89] Miloshevich SOP, at p. 12.

estimating the value of reduced tower count enabled by carbon-core conductors, Mr. Craig assumed a cost per tower that is unsupported in the record and about 1/3 of that specified in the MISO Transmission Planning Guide.[90] Due to these choices, Mr. Miloshevich contends that the Commission should give Mr. Craig's rebuttal testimony little weight. Mr. Miloshevich also refers to evidence in the record demonstrating both capital and operational savings resulting from the application of carbon-core conductor from TS Conductor in a transmission project recently completed by Basin Electric.[91]

C. Analysis and Findings

1. Burden of Proof

51. Except as otherwise provided by statute, the Administrative Procedure Act imposes the burden of proof in administrative adjudicatory proceedings upon the proponent of an order. § 24-4-105(7), C.R.S. Therefore, any party seeking an order by the Commission bears the burden of proof with respect to the relief sought by a preponderance of the evidence. *Id.;* C.R.S.; Rule 1500 of the Commission's Rules of Practice and Procedure, 4 CCR 723-1. However, as in this case, since the Commission must determine whether the Settlement Agreement provisions proposed by the Joint Parties are not contrary to the public interest, the burden of proof lies with the Settling Parties.[92] This standard requires the finder of fact to determine whether the existence of a contested fact is more probable than its non-existence. *Swain v. Colorado Dep't. of Revenue*, 717 P.2d 507, 508 (Colo. App. 1985). If an intervenor advocates that the Commission should adopt its position, then that intervenor must meet the same burden of proof with respect to its

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90 *Id*. at 12-13.

91 HE 1703, Miloshevich Response to Public Service 3-2; HE 1703, Attachment LM-1; Hearing Exhibit 1703, Attachment LM-2.

92 Similarly, the parties supporting the Partial Stipulation, and thus advocating that the Commission adopt their position, must meet the same burden of proof with respect to the Partial Stipulation.

advocated position. The evidence must be "substantial evidence," which the Colorado Supreme Court has defined as "such relevant evidence as a reasonable person's mind might accept as adequate to support a conclusion … it must be enough to justify, if the trial were to a jury, a refusal to direct a verdict when the conclusion sought to be drawn from it is one of fact for the jury." *See, e.g.*, *City of Boulder v. Pub. Utils. Comm'n*, 996 P.2d 1270, 1278 (Colo. 2000).

52. Further, the Commission has an independent duty to determine matters that are within the public interest. *Caldwell v. Public Utilities Commission*, 692 P.2d 1085, 1089 (Colo. 1984). As a result, the Commission is not bound by proposals made by the parties.

2. Certificate of Public Convenience and Necessity for the Pathway Project

a. Standard

53. Public utilities are required under § 40-5-101, C.R.S., to obtain a CPCN from the Commission prior to constructing a new facility or system or the extension of an existing facility or system. In determining whether to grant a CPCN, the Commission considers whether the utility, by a preponderance of the evidence, has established: (1) a present or future need for the facility; (2) that existing facilities are not reasonably adequate and available to meet that need; and (3) that the utility has evaluated alternatives to the proposed facility. *e.g.*, Decision No. R14-1405, issued November 25, 2014, Proceeding No. 14A-0287E. The impact on utility rates, and the magnitude of the underlying operating, maintenance, and capital costs, is also relevant to the public interest analysis. *City of Boulder*, 996 P.2d at 1277, 1279, n.5.

54. Under § 40-5-101(4), C.R.S., a public utility is entitled to recover the costs that it prudently incurs in constructing transmission facilities for which the utility has obtained a CPCN. These prudently incurred costs may be recovered through a separate rate adjustment

clause until the costs have been included in the utility's base rates, and the recovery shall be calculated using the utility's weighted average cost of capital, including its most recently authorized ROE on equity, on the total balance of construction work in progress related to such transmission facilities. § 40-5-101(4), C.R.S.

b. Discussion

55. The Power Pathway Project is one of the most expansive and significant transmission proposals to be considered by the Commission. This proposal comes at a critical time for Public Service, Colorado's largest utility, to transform its system and the ways in which it reliably generates and delivers energy for its customers in advance of clean energy targets applicable to the Company in 2030 and economywide greenhouse gas emission reduction goals. We also recognize that the costs associated with the Pathway Project are significant as proposed, and that a project of this magnitude may result in the potential for substantial cost overruns. It is with this awareness that we carefully and thoroughly considered the voluminous record in this Proceeding.

56. As an initial matter, the Commission does not agree with the contention of LS Power that the Pathway Project is a regional project or that the Company failed to follow any necessary Federal Energy Regulatory Commission (FERC) processes. Public Service must comply with the transmission project planning provisions in its Joint Open Access Tariff for local transmission projects. The Power Pathway Project is local in scope because it is wholly owned by Public Service, is built for the benefit of the existing system, and serves the Company's customer base. The Commission declines to find that the Company should have submitted the Project to the WestConnect Regional Process as a regional project for transmission planning.

57. We agree with the Settling Parties that the Company has met its burden of proof and has sufficiently demonstrated the need for all five segments of the Pathway Project. Without the additional injection capacity provided by the Project, Public Service will be unable to interconnect the quantity of renewable resources it requires to decarbonize its generation fleet in accordance with the mandates of SB19-236. More specifically, we are persuaded by the Settling Parties that without the proposed transmission backbone in Eastern Colorado allowing for access to solar and wind resources in ERZs 1, 2, 3, and 5, it is very unlikely that Public Service will be able to meet the 80 percent emissions reduction target by 2030 and its projected 2030 peak summer load.[93] We agree with the Settling Parties that waiting to approve the Pathway Project until after the approval of the development or acquisition of new renewable generation would threaten the timely completion of necessary transmission, so that the transmission lines may not be constructed by the time the new generation resources are ready to be placed in service and necessary to meet emission reduction targets.

58. Further, we are convinced by testimony of Public Service and the Settling Parties that the Project is appropriately sized, contrary to arguments put forth by the Stipulating Parties, LS Power, and Mr. Miloshevich. Through its testimony, and specifically its discussion of alternatives considered by the CCPG 80X30 TF, we find Public Service has demonstrated the need for transmission infrastructure that can accommodate coincident injection of approximately 3,000 to 3,500 MW of electric power from new generation. While the Company and Settling Parties note that the preferred portfolio in the 2021 ERP and CEP would leave some unutilized capacity on the Pathway Project, we are nonetheless convinced the Project will be fully utilized

[93] In the event of material changes concerning the Company's plans, for example if the final outcome in the 2021 ERP and CEP Proceeding demonstrates a significant decrease in expected resource acquisition, the Commission may entertain appropriate avenues to ensure our finding of need for the CPP remains applicable.

in the near future as Public Service and other utilities take further steps towards emission reduction goals beyond 2030 and meet other initiatives such as beneficial electrification.

59. We also find that the construction of a networked transmission backbone in Eastern Colorado, in a looped configuration that allows access to diverse wind and solar resources, will provide numerous benefits to ratepayers beyond enabling Public Service and the State of Colorado to meet emission reduction targets. The Company and the Settling Parties have established that the Pathway Project will improve the reliability and resiliency of the Colorado transmission system,[94] which is increasingly important as the state depends on larger numbers of variable energy resources and will provide many operational benefits.

60. While the Company did not quantify the benefits associated with centralized transmission development, we nevertheless agree that the numerous long radial lines and gen-tie lines necessary to reach resources in remote areas in Eastern and Southeastern Colorado in the absence of the Pathway Project would, in the long run, increase costs and result in reduced reliability. We agree that the alternative – siting renewable development near existing transmission – would increase costs as bidders compete for scarce productive land.

61. Accordingly, we reject the Stipulating Parties' proposal, and the proposals of LS Power and Mr. Miloshevich, to grant a CPCN for only part of the Pathway Project. The Stipulating Parties' contention that Segments 1, 3, 4, and 5 should be contingent on a specified MW amount of bids received in Phase II of the 2021 ERP and CEP ignores not only the Company's demonstration of present and future need, but also reliability benefits of the entire looped Project and the significant cost benefits of providing bidders with certainty as to

[94] *E.g.*, Hr. Ex. 2000, Answer Testimony of Kenneth Wilson; Hr. Ex. 1400, Answer Testimony of Arne Olsen; Hr. Ex. 700, Answer Testimony of P. Jay Caspary.

transmission capacity and the date on which that capacity will be available at specific interconnection locations. Further, certain Stipulating Parties and LS Power contend that portions of the Project should be delayed so that competitive procurement or additional regional planning options may be explored. However, this ignores that either option would require substantial Commission process and additional time, including time for potentially contentious Commission rulemakings, as well as time for the development of a regional market and transmission planning activities of the regional market.[95] Given impending emission reduction targets, the resilience and reliability benefits offered by a looped configuration, and the long timelines involved with transmission construction, we decline to take a piecemeal approach to approval of the Pathway Project.

62. We find that Public Service and the Settling Parties have demonstrated that the public convenience and necessity requires construction of the Pathway Project. Existing facilities are not adequate or available to meet the need for increased transmission capacity to serve required new renewable generation or to provide the reliability and resiliency necessary to support a system highly dependent on variable resources, and other alternatives will not negate the need for the Project. We conclude that the terms of the Settlement Agreement at paragraphs 1 and 2 are in the public interest, and therefore grant a CPCN for Segments 1 through 5 of the Pathway Project. To be clear, this Decision grants a single CPCN for the entire Pathway Project.

63. While we grant a CPCN for the Pathway Project, we are keenly aware that ratepayers will be impacted by the substantial costs associated with the Project and we are reminded of our statutory duty to ensure safe and reliable utility service at just and reasonable rates. Indeed, a need finding is implicitly contingent on certain cost expectations. A line that is

[95] This issue is further examined in Section I.C.8.c.

needed at one cost, may not be required at a much higher cost. To ensure that the cost of the Pathway Project and the burden on ratepayers does not outweigh the public interest in granting the Project a CPCN, and that the general cost expectations associated with the need finding are met, we implement a PIM that sufficiently incents Public Service to maintain cost containment and budgetary discipline as set forth in Section I.C.4 of this Decision.

c. Conditional CPCN for the MVL Extension

64. We determine that the Settlement Agreement's proposal for the MVL Extension is in the public interest. Public Service explains that although the extension is not required to meet its statutory emission reduction requirements, it would provide transmission infrastructure to support development in wind-rich areas of southeastern Colorado and would prevent the need for developers to build multiple costly, unreliable, and lengthy gen-tie lines to connect to the Pathway Project. We note that the Settling Parties' proposal to grant a conditional CPCN for the MVL Extension that would be triggered upon the inclusion of the extension in the final resource plan approved in Proceeding No. 21A-0141E is the same as the Stipulating Parties' proposal, excepting the Stipulating Parties' treatment of Segment 3. We find that approval of a final resource plan in the 2021 Public Service ERP and CEP that includes the MVL Extension would demonstrate need for the extension in an area not currently served by adequate transmission. We therefore conditionally grant Public Service a CPCN for the MVL Extension as proposed by the Settlement Agreement in paragraphs 17 to 23.[96] The PIM set forth in Section I.C.4.a would also be applicable to the MVL Extension, should the Company's CPCN be affirmed.

[96] The Commission does not adopt paragraph 24 of the Settlement concerning the PIM applicable to the MVL Extension.

d. Pathway Project Costs and Timeline

65. The Settling Parties agree that the construction sequencing and timeline as presented in Attachment BJR-5 is "reasonable and in the public interest" given the timing of the clean energy resource acquisition expected through the 2021 CEP and ERP and the 2030 clean energy target set by §40-2-125.5(3)(a)(I), C.R.S.[97] The Company proposes a completion date for construction and testing of Segments 2 and 3 on September 2, 2025, Segment 1 on May 14, 2026, and Segments 4 and 5 on May 13, 2027.[98] Notably, with the proposed schedule, Segments 2 and 3 would be in service in time to bring projects online prior to the end of 2025, when PTCs and ITCs on renewable energy projects are currently projected to expire.

66. The Commission finds the preliminary summary schedule provided by the Company[99] and projected in-service dates reasonable and in the public interest. The Company, and in turn the ratepayers, may face significantly increased costs for the loss of federal tax incentives if the Project is not delivered in time to interconnect those resources. We stress the importance of this Project remaining on time to meet the in-service dates as proposed.

e. Project Cost Recovery

67. We acknowledge that the Power Pathway Project is virtually unprecedented in scope and cost in Colorado history. The Commission is aware that a project of this magnitude will have a significant impact on rates charged by the Company to customers. As part of the decision-making process in this proceeding, the Commission, carrying out its primary function to ensure the health, safety and welfare of Colorado citizens, has balanced the significance of these rate impacts with the statewide public interest of expanded reliable transmission facilities,

[97] Settlement Agreement, at ¶ 5.
[98] HE 105, Direct Testimony of Brian J. Richter, Attachment BJR-5.
[99] *See* HE 105, Direct Testimony of Brian J. Richter, Attachment BJR-5.

especially in light of the Company's need to reduce emissions by 2030 and the overall state goal of carbon neutrality in the near-term future.

68. The Company is entitled to recover through a separate rate adjustment clause, the costs that it "prudently incurs in planning, developing, and completing" the construction or expansion of transmission facilities. § 40-5-101(4)(a), C.R.S. The Commission does not disagree that the Company may recover costs associated with the Power Pathway Project through the TCA rider. The Commission adopts this portion of the Settlement Agreement in paragraph 6.

69. The Settlement Parties agree that "no presumption of prudence will attach to the cost estimates for the Pathway Project" and that the Company bears the burden going forward to demonstrate actual costs incurred are prudent and reasonable when it seeks recovery of associated costs.[100] We agree with the Settling Parties on these points, and we expect that in addition to demonstrating that its actually incurred costs are prudent and reasonable, the Company will address whether its costs are within the estimates provided in this Proceeding. Therefore, we adopt Paragraph 6 of the Settlement Agreement.

3. Magnetic Field and Noise Levels

70. In its Application, Public Service requests a finding of reasonableness for the expected maximum magnetic field and noise levels included in the Application, in compliance with Rule 3206(e) – (f), 4 CCR 723-3 of the Commission's Rules Regulating Electric Utilities. The Settling Parties agree that the expected maximum magnetic field and noise levels associated with the Pathway Project are reasonable and require no further mitigation or prudent avoidance measures.[101] No party has opposed such a finding of reasonableness. We agree with the Settling

[100] Settlement Agreement, at ¶ 6.
[101] Settlement Agreement, at ¶ 15.

Parties, and find that the expected maximum magnetic field and noise levels associated with the Pathway Project are reasonable.

71. The Company also submitted the expected maximum magnetic field and noise levels for the MVL Extension, in compliance with Rule 3206(e) – (f), 4 CCR 723-3 of the Commission's Rules Regulating Electric Utilities, and the Settling Parties agree that these expected levels are reasonable and require no further mitigation or prudent avoidance measures.[102] As with the levels associated with the Pathway Project, no party has opposed such a finding of reasonableness. We again agree with the Settling Parties and find that the expected maximum magnetic field levels associated with the MVL Extension are reasonable, in the event the conditional CPCN granted for the MVL Extension becomes unconditional.

4. Performance Incentive Mechanism

72. Commission Staff put forth in its answer testimony the idea of implementing a PIM for the Pathway Project.[103] While the Company did not include a PIM in its direct case, it did propose one on rebuttal and the Settlement Agreement contains a PIM (Settlement Agreement PIM).[104] The Settlement Agreement suggests establishing a PIM focused on costs over which the Company claims are reasonably within its discretion and control, and that excludes costs over which it claims it does not exert such discretion and control.[105] The costs subject to the PIM would be those related to engineering, permitting, project management,

[102] Settlement Agreement, at ¶ 22.
[103] *See* Hearing Exhibit 1500, Staff Witness Gene L. Camp Answer Testimony, Rev. 2, at pp. 36-39.
[104] Settlement Agreement, at ¶¶ 7-14.
[105] *See* Public Service Joint SOP, at p. 10.

construction, labor, and overhead.[106] The Settlement Agreement PIM excludes costs related to right-of-way, easements, environmental compliance, and materials.

73. The Settlement Agreement proposes a PIM calculated on a yearly basis evaluated for costs associated with the segments scheduled to be placed in-service during each calendar year. The Company targets Segments 2 and 3 and associated substations for completion in 2025, Segment 1 and related substation expansion for completion in 2026, and Segments 4 and 5 and related substations for completion in 2027.

74. Per the Settlement Agreement, outside of a positive and negative 5 percent dead band relative to the Company's cost estimate (including its risk reserve) within each year, a series of symmetrical ROE basis point adjustments apply.[107] Once costs are outside the dead band, an ROE adjustment applies to the return on excess costs or savings. The PIM structure applies three symmetrical adjustments that decrease or increase the ROE as costs become greater or less than the original Company cost estimate. If line miles for segments planned for completion in a given year exceed 110 percent of the line miles presented in the Company's Application, any savings will be returned to ratepayers.

75. According to the Settlement Agreement, the penalty or bonus calculated for expenditures in each completion year (2025, 2026, or 2027) would be amortized over ten years. The Company would collect any penalty or bonus through the TCA and if the amortization of a PIM penalty or bonus extends beyond the period in which associated Pathway Project capital is

[106] Settlement Agreement, at ¶ 8.
[107] Settlement Agreement, at ¶¶ 7-14.

recovered through the TCA, ratemaking treatment of a PIM penalty or bonus in the TCA is still reasonable.[108]

76. The Settlement Agreement PIM includes certain provisions to incentivize meeting the in-service target dates. For example, if costs exceed 105 percent of budget for a completion year and the associated segments/substations are not placed in service by the end of that year, 50 basis points will be added to the associated penalty. If costs are below projections but the segments and substations for a given year are not placed into service by the end of that year, all savings will be returned to ratepayers (*i.e.*, there will be no bonus for the Company).

77. The Commissioners discussed at the Hearing and at the Commissioner's Weekly Meeting on November 24, 2021, the importance that any adopted PIM incentivizes timely performance. In response, the Company provided alternative considerations to the Settlement Agreement PIM in its SOP.[109] In its SOP, Public Service indicates that the Settling Parties "do not oppose" an increase of 75 basis points to the ROE adjustments for each tier of cost overrun or savings for segments and substations planned for completion in 2025 only (Segments 2 and 3).[110]

78. The Partial Stipulation provides an alternative PIM (Stipulation PIM) with a fundamentally different structure.[111] While the Stipulation PIM groups the Project segments into the same in-service years as proposed in the Settlement Agreement, it caps costs at the estimates the Company provides in its Application, inclusive of its risk reserve. The Stipulation PIM's cost caps include cost categories excluded by the Settlement PIM. No cost overruns would be borne by ratepayers. The Company would earn $1 million of every $10 million saved relative to its cost

[108] Settlement Agreement, at ¶¶ 7-14.
[109] Public Service Joint SOP, at pp. 14-15.
[110] Public Service Joint SOP, pp. 16-17.
[111] Partial Stipulation, at ¶¶ 11-12.

estimates (including all categories of costs), the remainder going to ratepayers. Savings eligible for this 10 percent incentive will be calculated in increments of $10 million, so that the Company would earn $1 million for savings of $10 million, earn $2 million for savings of $20 million, and so on. Any incentive otherwise due to the Company would be forfeited if in-service date targets are not met.

79. The Stipulating Parties also provide certain updates to their proposed PIM structures in light of discussions by the Commissioners at Hearing and at the Commissioners' Weekly Meeting on November 24, 2022. In their SOPs, the Stipulating Parties suggest that the Stipulation PIM could be modified such that any cost overruns or savings beyond a 10 percent buffer in the cost categories over which the Company asserts it has no control (inclusive of risk reserve) could be shared on a 50/50 basis between the Company and ratepayers. The Stipulating Parties also encourage the Commission to consider the high cost to ratepayers if Segment 2 (the only segment the Stipulating Parties suggest the Commission grant a CPCN for) is not completed by 2025 (which could result in the loss of federal tax credits to interconnecting wind and solar projects) and suggest that the Commission require the Company to forfeit the return of the cost of Segment 2 in that case.[112]

80. The Commission has previously instituted PIMs as part of approval of various utility programs and generation projects. We believe that in certain instances, performance-based mechanisms can be important tools to incentivize utility action to reduce greenhouse gases and ensure timely and cost-efficient completion of generation and transmission building projects.

[112] UCA SOP, at pp. 22-24; CEC and Climax SOP, at pp.18-20.

81. In identifying an acceptable PIM structure, we find it appropriate to articulate and adopt the following principles of a desirable PIM for the Pathway Project, which derive largely from testimony by Staff and Public Service (PIM Principles):[113]

a. The PIM should have a clearly and unambiguously defined penalty and incentive structure;
b. The PIM should be clearly and unambiguously focused on one or a small number of objectives that are not already the subject of an alternate PIM or pre-existing utility incentives;
c. The PIM should create the ability for all parties to clearly and unambiguously identify success or failure on the basis of a pre-defined baseline and pre-defined performance metrics;
d. The utility subject to the PIM should have control over factors determining its success or failure;
e. The PIM should establish penalties or incentives that scale symmetrically with the degree of success or failure in achieving the pre-defined metrics, but should be neither excessively punitive nor lucrative and must be in conformance with existing law;
f. The PIM should establish penalties or incentives that are of a large enough magnitude to supersede other factors (*e.g.*, return on equity) that influence Company behavior;
g. The PIM should avoid gaming and unintended consequences (to the degree these can be anticipated); and
h. The PIM should complement and inform utility performance evaluation.

82. We emphasize the unique nature of the Pathway Project, and in particular the cost and timing considerations present in this proceeding, as well as the importance of cost expectations in the need finding. While the Company is expected to maintain strict cost control and efficient project management in all instances, we find that implementing a PIM is an appropriate incentive to ensure those goals are met for the Pathway Project. The Commission anticipates a PIM to act in conjunction with a forthcoming prudency review under

[113] Hearing Exhibit 1500, Staff Witness Gene L. Camp Answer Testimony and Attachments, Rev. 2, at pp. 39-40; Hearing Exhibit 112, Rebuttal Testimony and Attachments of Brooke A. Trammell, at pp. 45-46.

§ 40-5-101(4)(a), C.R.S., to maintain appropriate cost control and timing protections. Implementing a PIM for the Pathway Project provides the Commission with an additional tool to align utility incentives with the interests of ratepayers at the onset of Project development. In light of the PIM Principles and interests outlined above, the Commission finds it appropriate to order a PIM here to encourage the Company to maintain adequate cost control and meet its' intended in-service dates. The circumstances of this Project require a PIM structure that appropriately balances risks between ratepayers and shareholders.

83. The Commission is tasked with protecting the public interest regarding utility rates and practices.[114] Consequently, the Commission is particularly concerned with adopting a PIM that ensures sufficient discipline by the Company in keeping costs and timing appropriate. In applying the PIM Principles stated above to the Settlement Agreement PIM, and in reviewing the record before us, we find that the Settlement Agreement PIM largely meets those principles except the principle that penalties and incentives be of sufficient magnitude to supersede other factors that could influence Company behavior. Therefore, the Commission adopts the Settlement Agreement PIM in form, with certain modifications to magnitude and applicability (described below), to ensure the PIM Principles and the Commission's duty to protect ratepayers and ensure the cost expectations around the need finding are met, while appropriately balancing risk between ratepayers and shareholders of the Company.

84. Considering the PIM recommended by the Stipulating Parties, we find that it is inconsistent with the principles that a utility should have control over factors determining its

[114] The PUC has a general responsibility to protect the public interest regarding utility rates and practices. *See* § 40-3-102, C.R.S.; *Montrose v. Pub. Utilities Com.*, 629 P.2d 619, 624 (Colo. 1981).

success or failure and that a generally symmetric scale is appropriate. The Stipulation PIM would place the full burden of any cost overrun on the Company, even for those cost categories it asserts it has no control over. The Stipulation PIM is also asymmetric, excessively punitive, and the proposed hard cost cap may prevent the future recovery of prudently incurred costs by the Company.

85. We retain the key characteristics of the Settlement Agreement PIM including, largely symmetrical penalties and bonuses; a 5 percent budget "dead band" inside of which no penalty or bonus will apply; penalties or bonuses that scale in proportion to the degree of departure from the estimated budget; and, aggregation of costs into in-service years. We also find it appropriate to incorporate the concept existing in both the Settlement and Stipulation PIMs that there should be separate incentive components focused on cost control and timely segment completion. Given the time pressures associated with federal tax credits, timeliness is an essential component of successful completion and should function independently from the budgetary component.

a. Cost Control PIM

86. We first address the PIM components focused specifically on cost control. As Public Service notes, no party contests its cost estimates.[115] We therefore largely adopt those cost estimates, inclusive of the Risk Register, as the baseline cost estimate for the PIM.[116] The one exception we make is to exclude the numerous line items in the Risk Register, with an aggregate multi-million dollar value, identified as "Unknown risks."[117] Although the Company ascribes

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[115] Public Service Joint SOP, at p. 4.

[116] The use of the cost estimates put forth by the Company as a baseline for the PIM, as proposed by the Settlement Agreement and adopted here, is indicative of the reasonableness of the formulation of the estimate and has no import with regard to any future prudency review. *See also Section II.C.2.e.*

[117] Hearing Exhibit 115, Attachment BJR-14HC.

100 percent probability of occurrence to these risks, it makes no attempt to describe what these risks might be and presents no evidence in support of either the dollar value associated with each such item or why it is certain to occur. Without such support, the Commission declines to incorporate these items into the cost estimate baseline against which Company performance will be evaluated.

87. In its rebuttal testimony, the Company distinguishes between cost categories that are within its control and those that it asserts are outside its control. It makes this distinction to separate costs that it believes should be subject to a PIM from those it believes should be excluded. Specifically, the Company asserts that costs related to: 1) Project design and scope; 2) the labor hours needed to construct it; 3) the quantity of materials (e.g., conductors, steel for towers, concrete); and 4) scheduling and permitting (the Full-Control Categories) are all within its control and should be subject to a PIM. Conversely, the Company asserts it has no control over: 1) commodity pricing; 2) the cost of permits and land acquisition; 3) labor costs; or 4) delays imposed by regulators or other third parties, including environmental costs, and so these costs should not be subject to a PIM (the Limited-Control Categories).[118]

88. We agree in principle with the Settlement Agreement PIM that the Company is in control of certain costs to a greater degree than others. As we note above, the utility should have control over factors determining its success or failure when developing a successful PIM. As such, we find it appropriate to adopt a two-part cost control PIM reflecting the differing degrees of control the Company has over the Full- and Limited-Control cost categories.

[118] Settlement Agreement, at ¶ 8.

89. There is one category of potentially significant cost that is clearly beyond company control, and that is the cost of environmental compliance, particularly should the Lesser Prairie Chicken be listed by the U.S. Fish and Wildlife Service (USFWS) as an endangered species. In rebuttal testimony, Company witness Carly R. Rowe explained that the USFWS is currently contemplating listing the Lesser Prairie Chicken as an endangered species, and that a final rule on this matter is expected in the second quarter of this year. Ms. Rowe stated that if the USFWS does list the Lesser Prairie Chicken as endangered, this would impact Segments 3, 4, and the MVL Extension. For these segments, habitat conservation costs could be as high as $3.5 million per line mile, and could increase total costs for these segments by up to $180 million.[119] We agree with the Company that it would be unreasonable for the Commission to penalize it if its siting costs are increased due to the listing of the Lesser Prairie Chicken as an endangered species, and we are mindful of WRA's concern that including environmental compliance costs in the PIM structure could create incentives for the Company to "cut corners" when it comes to environmental compliance.[120] Accordingly, environmental compliance costs shall be excluded from both the baseline and actual incurred costs in the calculation of the Limited-Control component of the PIM.

90. We acknowledge that the Company has substantially less influence over the Limited-Control Categories, but we do not agree that its influence is completely nonexistent. For example, it is the Company that will negotiate with landowners over the cost of land and easements, will determine the precise route of each segment, and will sign contracts for the delivery of materials with specific suppliers. While the Company has no control over global

[119] Hearing Exhibit 117, Rebuttal Testimony and Attachments of Carly R. Rowe, at pp. 17-20.
[120] WRA SOP, at pp. 14-15.

commodity markets, it does exert a degree of control in each of these areas via the decisions it makes and in its negotiation and contracting strategy. We expect the Company to exercise its best judgment in decision-making and in negotiating to the best advantage of ratepayers. Accordingly, we adopt certain PIM provisions specific to Limited-Control Categories, further described below.

91. The Settlement Agreement PIM, in a worst-case scenario, would require the Company to bear less than 9 percent of the added cost, equating to less than 18 percent of the additional return ratepayers would pay to the Company on the cost overrun. We find the PIM Principle, that the PIM should establish penalties or incentives that are of a large enough magnitude to supersede other factors (*e.g.,* ROE) that influence Company behavior, to be of key importance to the adopted PIM design. We find that the Settlement Agreement PIM can be improved, with respect to basis point adjustments as described below, to better influence Company behavior.

92. We now turn to describing further the Settlement Agreement PIM as adopted and modified by this Decision. The PIM adopted here starts with the Company cost estimate, as adjusted in Decision paragraph 86, as the PIM baseline. The Pathway Project PIM will evaluate costs on a year-by-year basis based on Segment in-service dates as proposed in the Settlement Agreement.[121] We maintain a 5 percent cost estimate “dead band” inside of which no penalty or bonus will apply as proposed in the Settlement Agreement.[122] From there, the penalties or bonuses scale in proportion to the degree of departure from the cost estimate.

93. The PIM proposed by the Settling Parties (as modified in the Company’s SOP) would expose the Company to a penalty that in the worst case would amount to a net present

[121] Settlement Agreement, at p. 11.
[122] Settlement Agreement, at p. 11.

value of less than 9 percent of the cost overrun (relative to included cost categories only), and would impose a small penalty, if any, for late completion of segments. The Stipulating Parties, on the other hand, recommend a cost control PIM that would hold the Company responsible for 100 percent of any cost overruns (regardless of cost category) while allowing it to share, at best, 10 percent of any savings. We find that given the significant and real uncertainties the Company faces in completing a project of this magnitude and duration, the PIM proposed by the Stipulating Parties is excessively punitive, but the Settlement PIM needs a stronger incentive to function properly. Therefore, for the Full-Control Categories, outside of a 95 percent to 105 percent dead band relative to the Company's cost estimate (inclusive of the risk reserve adjusted as discussed above), 25, 50, and 75 basis point adjustments will apply to the ROE of the <u>entire</u> investment for the line segment and substation groupings planned for completion in 2025, 2026 and 2027.

94. Also, for the Full-Control Categories, the 25-point ROE adjustment will apply to cost differences (positive or negative) greater than 5 percent and up to 10 percent relative to the baseline budget. The 50-point ROE adjustment will apply to cost differences greater than 10 percent and up to 15 percent relative to the baseline budget. Cost differences greater than 15 percent will be subject to an ROE adjustment of 75 basis points.[123]

95. As discussed above, with regard to cost variances in the Limited-Control cost categories, we find it appropriate for the Company to shoulder a smaller fraction of the risk that costs in these categories could be higher than it has estimated, and also that it should be able to

[123] This structure will result in the Company being exposed to a bonus or penalty amounting to approximately 10.8 percent, 15.0 percent, and 22.5 percent of the cost overrun or cost savings for the three tiers of budget variance discussed above.

retain a similar fraction of the benefit, should its actual costs in these categories come in below its projected costs.

96. Accordingly, we will adopt the following adjustments on the Limited-Control cost categories: Outside of a 95 percent to 105 percent dead band relative to the Company's proposed cost estimate (inclusive of the risk reserve adjusted as discussed above and excluding Environmental Compliance costs), 50, 100, and 150 basis point adjustments will apply to the ROE of **only the cost overrun or cost savings** (again, excluding environmental compliance costs) for the line segment and substation groupings planned for completion in 2025, 2026 and 2027. The 50-point ROE adjustment will apply to cost differences (positive or negative) greater than 5 percent and up to 10 percent relative to the baseline budget. The 100-point ROE adjustment will apply to cost differences greater than 10 percent and up to 15 percent relative to the baseline budget. Cost differences greater than 15 percent will be subject to an ROE adjustment of 150 basis points.[124]

97. For both the Limited-Control cost categories, and the Full-Control cost categories of the Pathway Project PIM, annual penalties or bonuses shall apply for ten years, shall be amortized over ten years, and shall be collected via the TCA in the manner provided for in paragraph 12 of the Settlement Agreement.

98. For both the Limited-Control cost categories and the Full-Control cost categories of the Pathway Project PIM, the Company may file appropriate pleadings to seek relief from application of the PIM, if events beyond its control occur. If the Company seeks a variance from the Pathway Project PIM components set forth in this Decision, it should describe how events

[124] The above structure will result in the Company being exposed to a bonus or penalty amounting to approximately 2 percent, 4 percent, and 6 percent of the cost overrun or cost savings for the three tiers of budget variance.

outside its control made it impossible to build some or all portions of the Pathway Project within the cost estimate presented in this proceeding.

99. In addition, should the evaluation of carbon core conductors (that we order below in Section I.C.7.b) indicate that the initial cost of carbon core conductors is higher than the conventional ACSR conductor but that it is cost-effective over its lifetime due to, for example, reduced line losses or other benefits, we encourage the Company to submit appropriate filings regarding any requested changes to application of the PIM or relevant baselines.

b. Timing Provisions

100. Our goal in establishing a Power Pathway PIM is to better align the interests of shareholders with those of ratepayers by incentivizing both on-time completion and cost control. As discussed above, we find it necessary and appropriate to implement an incentive component designed to motivate the timely completion of all Power Pathway segments and substations, and particularly for Segments 2 and 3 and the Pawnee, Canal Crossing, Goose Creek and May Valley substations at which they terminate. Segments 2 and 3 and their associated substations are of particular concern given the Company's intent to complete them in September 2025, thereby allowing interconnecting wind generating resources to be eligible for the federal PTC, which expires at the end of that year, and allowing interconnecting solar generators to be eligible for the federal ITC, which declines from 26 percent to 10 percent at the end of 2025.

101. The proposals for timing PIMs from the Settling Parties and the Stipulating Parties are at opposite extremes. The Settling Parties suggest that an additional ROE penalty of 50 basis points would apply if the Company does not deliver a segment in-service in their target year and if actual costs exceeded 105 percent of the Company estimate of controlled costs. If segments were placed in service late and costs were below 95 percent of that estimate, the

Company would be ineligible to claim any savings, but there would be no further penalty. A project falling within the budgetary PIM dead-band would not carry a penalty related to timeliness. The Partial Stipulation specifies that any shared savings otherwise due to the Company would be forfeited if the relevant segment is not placed into service as the Company projects. Regarding Segment 2 specifically (which is the only segment the Stipulating Parties believe should be granted an unconditional CPCN), the Stipulating Parties suggest in their SOPs that the Commission consider disallowing the full investment in that segment and its associated substations if they are not placed into service by their target date.

102. In our judgement, a potential penalty or bonus of $10 million, for late or early completion of Segments 2 and 3 will provide a sufficient incentive to align those interests. Because the timing of the completion of the remaining segments is not critical for federal tax credit eligibility, we find that a smaller incentive, but one proportional to the magnitude invested in each segment grouping is appropriate. The $10 million maximum penalty or bonus we adopt for Segments 2 and 3 amounts to 1.43 percent of the Company's aggregate $699.3 million cost estimate for those segments (inclusive of the risk register). We will adopt one-quarter of this percentage, or 0.36 percent as the maximum penalty or bonus that will apply to the remaining segment groupings. These penalties or bonuses will be assessed or granted on a dollar per day basis dependent upon when each segment grouping is placed into service, as discussed further below.

103. The record demonstrates that the Company plans to complete Segments 2 and 3 and their associated substations by September 2, 2025, Segment 1 and the expansion of the Ft. Saint Vrain substation is projected to be complete by May 14, 2026, and Segments 4 and 5

and associated substations are projected to go into service by May 13, 2027.[125] Putting Segments 2 and 3 into service on or near September 2, 2025 should enable substantial capacities of wind and solar resources selected through the ongoing 2021 ERP and CEP to interconnect and demonstrate commercial operation before the end of that year, qualifying them for receipt of the federal tax credits. We therefore find it appropriate to center our timing PIM on that date. We also find it appropriate to establish a “timing dead-band” of 15 days on either side of that date during which no bonus or penalty will apply. Because it will become increasingly difficult for developers to interconnect and demonstrate commercial operation as the end of 2025 approaches, the daily penalty for late completion will escalate until December 20, 2025, after which it will cease.

104. Because the consequences of late completion for Segments 2 and 3 scale dramatically as the end of 2025 approaches, we find it appropriate that the magnitude of the daily penalty should increase linearly following the end of the timing dead-band until the end of the year—a period of 96 days. Therefore, the penalty for late completion will commence on September 17, 2025 at a value of $50,000 and increase by $1,175.81 each day until December 20, 2025 on which date the daily fee will be $160,526.32. If this complete segment group is not completed before December 21, 2025, the total cumulative penalty assessed on the Company will be $10 million. If these segments and substations are completed prior to the commencement of the timing dead band on August 18, 2025, the Company will be awarded an incentive of $50,000 for each day in advance of that date up to, but no earlier than January 30, 2025 (with no daily increase). If the Company completes this segment group on or before January 30, 2025, it will be eligible for a total bonus of $10 million.

[125] Hearing Exhibit 105, Attachment BJR-5_ Power Pathway Summary Schedule Feb 25 2021.

105. For the remaining segments, we adopt a flat, symmetrical dollar-per-day incentive structure applied over a four-month period prior to and following a timing dead-band. The Company projects that Segment 1 will be completed by May 14, 2026 and that Segments 4 and 5 are to be completed by May 13, 2027.[126] Because these segments are to be built further into the future, we will expand the timing dead-band to 30 days before and after the projected completion dates for each grouping. As noted above, the penalty or incentive for each grouping is capped at 0.36 percent of the total projected budget. For Segment 1 this total is projected at $243,378,862, so the maximum penalty or bonus shall be $897,764, or approximately $7,481 per day. This daily amount shall be a bonus for early completion between December 15, 2025 and April 14, 2026, and a penalty for late completion between June 13, 2026 and October 11, 2026. The total projected expenditure for Segments 4 and 5 is $746,818,721, so the maximum penalty or bonus shall be $2,688,547, or approximately $22,405 per day. This daily amount shall be a bonus for early completion between December 14, 2026 and April 13, 2027, and a penalty for late completion between June 12, 2027 and October 10, 2027.

106. The Timing PIM annual penalties or bonuses shall apply for ten years, shall be amortized over ten years, and shall be collected through the TCA in the manner provided for in the Settlement Agreement in paragraph 12. As with the cost-control PIM discussed earlier, the Company may seek relief from the Commission if extraordinary events beyond its control make it impossible to complete one or more segments by the dates specified in its Application and supporting Testimony. If the Company seeks a variance from the PIM components set forth in this Decision, it should describe how extraordinary events outside its control made it impossible

[126] Hearing Exhibit 105, Attachment BJR-5_Power Pathway Summary Schedule.

to build some or all portions of the Pathway Project within the timeframe presented in this proceeding.

107. Finally, if the expiration date for the PTC or the date on which the ITC drops from 26 percent to 10 percent are extended by the federal government, the critical dates for completion of segment groupings will change. In this case, the Commission notes that the Company may similarly file a motion in this Proceeding to reconsider the timing PIM mechanism described above.

108. The Settlement Agreement PIM is therefore adopted as modified consistent with the discussion above. The Commission declines to adopt the PIM methodology set forth by the Stipulating Parties.

5. San Luis Valley Transmission M-Docket

109. The Pathway Project does not include any proposed transmission expansion to ERZ 4 in the San Luis Valley which contains significant potential for solar development.[127] The Settlement Agreement recommends the Commission open a miscellaneous proceeding to further solicit comments and study the potential value of transmission solutions in and out of the San Luis Valley in southern Colorado.[128]

110. At hearing, Staff witness Mr. Gene Camp noted that exploration of transmission in the area is "probably well worth the time" to study. COSSA/SEIA further note in their SOP that the San Luis Valley is one of the "best solar potential" areas in Colorado and the potential for solar growth in the area "will need to be exploited to fulfill Colorado's renewable energy

[127] HE 1600, Answer Testimony of Mike Kruger on behalf of COSSA/SEIA, p. 8.
[128] Settlement Agreement, at ¶ 29.

goals."[129] Notably, no party expressed opposition to further study of transmission solutions for the area.

111. We agree that it is worthwhile to explore this issue. As proposed by paragraph 29 of the Settlement Agreement, the Commission will open a miscellaneous proceeding to solicit comments and consider the benefit of transmission solutions for the San Luis Valley no later than six months after the effective date of this Decision.

6. Owner's Engineer

112. At hearing, Chairman Blank explored the possibility of engaging a third-party independent expert to provide oversight of the Pathway Project management and procurement practices on behalf of ratepayers.[130] Chairman Blank notes that utilization of an Owner's Engineer with "real transmission equipment procurement and construction management expertise" to monitor investment decisions and spending, on behalf of customers, would likely be beneficial.

113. The Company and Staff address this idea through their Joint SOP.[131] Staff and the Company suggest the Commission order the Company to engage a third party with appropriate expertise for the Pathway Project and agree that the scope, parameters, and term associated with engagement of a third-party would be collaboratively established with input from both Staff and Public Service. This third party would be engaged by the Company to monitor the Project as directed by Staff on behalf of the Commission. Staff and Public Service commit to updating the Commission within 90 days of a final written decision in this Proceeding. The Company notes in the Joint SOP that it did not contemplate the costs associated with an Owner's Engineer when creating

[129] Statement of Position of the Colorado Solar and Storage Association and the Solar Energy Industries Association (COSSA/SEIA SOP), at p. 7.

[130] Hr. Tr. 11/15/2021 at 183:2-20 (Trammell cross by Chair Blank); Hr. Tr. 11/16/2021 at 67:11-21 (Camp cross by Chair Blank).

[131] Public Service Joint SOP, at pp. 27-28.

the cost estimate of the Pathway Project and thus could not be applied against an approved PIM. They state costs would be recoverable through the TCA. In COSSA/SEIA's SOP, they also note that the Commission should take steps to control costs of the Pathway Project as they find appropriate and that may include the use of an outside project engineer.[132]

114. The Commission finds the utilization of a third-party independent Owner's Engineer to be in the best interest of ratepayers and an important step to control costs of a major project such as the Power Pathway. Consequently, we adopt the proposal set forth by the Staff and the Company in the Joint SOP, with certain additional parameters.

115. In addition to the terms outlined in the Joint SOP, the Commission expects the Owner's Engineer to be hired and in place for oversight of the Pathway Project no later than December 31, 2022. Further, the Commission expects, at minimum, the Owner's Engineer to provide periodic reports to Staff and Staff to have management function over the Owner's Engineer's oversight of the Power Pathways Project. The Commission expects the Owner's Engineer to contract directly with Public Service, but for Staff to have management function over the Owner's Engineer role. Finally, we expect that the Owner's Engineer will be highly involved in the report on cost-effectiveness of ATTs required by Section I.C.7.b. Staff's oversight function should include notification to the Commission of any significant changes to project plans, budget extensions, timely segment completion, and observations of concerning project management reported.

116. The Commission directs the Company and Staff to file within this Proceeding, within 90 days of the issuance of this Decision, an update which describes the agreed-upon expected scope, estimated cost, and timeline for hiring a third-party for Project oversight. We direct the Company to file notice regarding the hiring of the Owner's Engineer, within this Proceeding, no later than December 31, 2022. The Commission also anticipates the Company will file any advice letter filing

[132] COSSA/SEIA SOP, at p. 6.

necessary to amend the TCA tariff to allow for recovery of the expenses related to the procurement of an Owner's Engineer for the Pathway Project.

7. Engineering Considerations

a. Undergrounding

117. Company witness Mr. Craig states that the Project as designed is sufficient to meet the 150 mG reasonableness threshold set forth in Commission Rule 3102(d), 4 CCR 723-3 of the Commission's Rules Regulating Electric Utilities and that undergrounding would entail significantly higher costs and environmental and technological impacts associated with burying the transmission lines.[133] He also states that underground lines present challenges during outages and faults in underground lines are typically more difficult to locate and repair than in overhead lines, leading to potentially significantly longer power outages than with overhead power lines.[134] The Settlement Agreement recommends the Commission adopt the certain language regarding the cost of undergrounding transmission lines for the Pathway Project.[135]

118. The Commission determines that Public Service's preliminary analysis establishes it would be prohibitively expensive to underground substantial portions of the Pathway Project, as undergrounding an AC transmission line of this magnitude would be prohibitively expensive compared to the cost of the Company's proposed above-ground design. In light of this differential in costs, placing all or substantial portions of the transmission lines underground would make the Project substantially more expensive and is not in the best interest of customers.

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[133] HE 106, Direct Testimony of Bryon R. Craig, at 68:5-88:22.
[134] *Id*.
[135] Settlement Agreement, at ¶ 30.

b. Advanced Transmission Technologies

119. Paragraph 16 of the Settlement Agreement states, in relevant part:

> Settling Parties agree that Public Service will present as part of any future transmission CPCN application(s) associated with the 2021 ERP & CEP follow-on transmission investment, a detailed explanation of ATT[136] considered for any project for which a CPCN is sought. In addition, the Settling Parties agree that the Commission should encourage the Company to engage with interested stakeholders regarding ATT through existing stakeholder processes, including the Colorado Coordinated Planning Group ("CCPG"), and report back to the Commission through the existing Rule 3627 Transmission Planning process.

120. The Commission has previously expressed its interest in the application of ATT in a Commissioner Information Meeting held on October 22, 2020, where the potential for several types of ATT were presented and discussed, and in Decision No. R21-0073 in Proceeding No. 20M-0008E issued February 11, 2021, in which the Commission required that Public Service, BHE, and Tri-State document their evaluation of ATT in all future transmission plans.[137] The Commission reiterates its ongoing interest in the application of ATT in Colorado wherever they can be cost-effectively deployed while maintaining or improving service reliability, and particularly where they can aid in the integration of renewable resources.

121. In light of the conflicting record in this proceeding on the costs and feasibility of utilizing ATT technology, the Commission declines to make any CPCN for the Power Pathway Project contingent upon technology choice or study. The Commission finds the record before us

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[136] Advanced transmission technologies (ATTs) comprise both advanced carbon-core conductors, high voltage DC transmission technologies, transmission-connected battery storage, and grid-enhancing technologies (GETs). GETs, in turn, include dynamic line rating, which enables utilities to vary transmission line rating depending upon real-time ambient conditions; power flow control devices, which actively control power flow on transmission lines; and topology optimization, which uses software to automate transmission line switching to optimize network power flow using real-time information about grid conditions.

[137] Decision No. R21-0073, ¶¶ 42 – 45.

deficient to determine what would be the economic consequences of utilizing carbon core conductors for this Project. Mr. Craig's rebuttal testimony identified errors undermining Mr. Miloshevich's analysis of capital and operating cost savings achievable by carbon-core conductors. Likewise, Mr. Miloshevich identified errors in Mr. Craig's analysis that bring the validity of his findings into question. The result is that the record on this very consequential decision regarding which conductor type would be best for the Power Pathway remains unclear. While we acknowledge that use of carbon core conductors could be very valuable for interconnecting additional renewable resources in the future, for minimizing curtailment, for increasing import/export capacity and to serve the Company's growing electrification load, it is also clear that requiring the Company to delay procurement of conductor pending resolution of further study could very well push completion of Project Segments 2 and 3 beyond the end of 2025, at substantial cost impacts for ratepayers.

122. In the instant proceeding, we agree with the parties that contend that no ATT can obviate the need for the substantial interconnection capacity in the solar- and wind-resource-rich areas of the state that the Pathway Project will provide access to. However, there remains the potential that some forms of ATT, namely carbon-core conductors, could possibly allow the Power Pathway Project to perform this function more efficiently, and potentially at lower cost than the conventional ACSR conductor favored by Public Service.

123. Accordingly, we decline to require Public Service to further study the use of carbon-core conductor for Pathway Project Segments 2 and 3. However, for the remainder of the Project, and for the MVL Extension, if it is ultimately granted an unconditional CPCN, we will require Public Service to conduct a formal cost-effectiveness analysis of carbon-core conductors. We order further study of the cost-effectiveness of carbon-core conductors to facilitate the

Company's decision making in planning the Pathway Project and to ensure a more complete record to aid our understanding of the relative costs of these technologies and the potential benefits to ratepayers.

124. We order the Company to solicit formal bids from carbon-core conductor manufacturers as required to complete this analysis. Within six months following publication of this Decision, the Company shall also complete and submit an analysis of the cost-effectiveness of carbon-core conductors. The analysis scope shall include, at minimum, the cost of conductors, installation labor and towers, and varying tower height and spacing as warranted by the properties of each conductor.

125. Public Service shall analyze two scenarios: one in which the capacities of Project components are unchanged from the current Pathway Project design, and one in which these components are upgraded as necessary so that the increased capacity of carbon-core conductors could be fully utilized. Although this latter scenario may imply additional upfront capital cost, the cost-effectiveness analysis shall assume the same load level as used in the first scenario. The analysis shall set forth costs and savings attributable to the use of carbon-core conductors over the expected life of the Project. Documentation of the analysis, including support for all assumptions, shall be filed as a report in this Proceeding.

126. We also direct the Company to provide the Owner's Engineer discussed in Section I.C.6 any information required for the Owner's Engineer to review and supply a report to the Commission. This review and report are to be considered a part of the scope of work of the Owner's Engineer.

127. If as a result of the analysis described above, the Company finds that carbon-core conductor would be advantageous for one or more segments of the Pathway Project, it may file a

motion to revise any relevant components of the cost-control and timing PIMs established above under § 40-6-112, C.R.S.

128. Paragraph 16 of the Settlement Agreement specifies in part that "Public Service will present as part of any future transmission CPCN application(s) associated with the 2021 ERP and CEP follow-on transmission investment, a detailed explanation of ATT considered for any project for which a CPCN is sought." In response, Mr. Miloshevich proposes that such a detailed explanation be required for any future CPCN, regardless of its connection to the 2021 ERP and CEP, and that the explanation include the Company's rationale in each case in which a conventional solution is selected rather than an ATT. Mr. Miloshevich also recommends that the Company be required to conduct a formal evaluation of cost-effective opportunities for ATT application on its existing transmission system.

129. We reiterate our ongoing interest in the cost-effective application of ATT. We find that it is a fundamental responsibility of all jurisdictional utilities in the state to stay abreast of technology developments (in transmission and all other areas of utility operations), and to identify and deploy new technologies wherever they provide ratepayer benefit. Failing to do so could risk cost disallowance, where a party can demonstrate that a utility's selection of a conventional technology solution resulted in elevated costs when the utility knew, or should have known, that an alternative technology (in this case ATT) could have provided equivalent or better service at lower cost.

130. However, we find that it would not be appropriate to require in this Decision the comprehensive, system-wide assessment of ATT opportunities that Mr. Miloshevich seeks. We do however, support and adopt paragraph 16 of the Settlement Agreement. While we decline to require such an assessment here, we note that the Commission will be evaluating the utilities'

consideration of ATT in the current joint Rule 3627 transmission planning Proceeding (22M-0016E) and will consider in that Proceeding whether new rules may be needed to spur more application of ATT. Such a rulemaking could examine whether independent analysis of ATT opportunities for the existing transmission system is warranted.

131. Mr. Miloshevich recommends the Commission adopt a PIM (using a "shared savings" approach) to advance the deployment of ATT.[138] We find that it would be inappropriate to order use of such a PIM within this Proceeding for this Project or for future transmission projects. Utilization of each ATT technology type may warrant a different PIM design and the variety of potential technologies available could preclude the use of a generalized PIM.

132. Within the instant Proceeding alone, we have found it necessary to adopt separate PIM components focusing on cost-control and timing, and each of these including multiple sub-components. While the shared-savings approach Mr. Miloshevich recommends could be warranted for several ATT applications, we are wary of pre-specifying a PIM structure for unknown future CPCN applications. Instead, we find that potential use of PIMs to incentivize adoption of ATT should be considered in individual CPCN applications as appropriate in the future and decline to order a PIM in this proceeding to advance deployment of ATT as proposed by Mr. Miloshevich.

8. Ancillary Issues

a. Rate Impact Cap

133. Staff witness Gene Camp provided an interpretation of the applicability of the rate impact cap in § 40-2-125.5(5), C.R.S., to the Pathway Project in his answer testimony.[139] Certain

[138] Miloshevich SOP, p. 7; *See also* HE 1700, Answer Testimony of Larry Miloshevich, at 62:10.
[139] Exhibit 1500, Staff Witness Gene L. Camp Answer Testimony, Rev. 2, at 14-15.

parties, including Public Service, filed a Joint Brief which addressed and generally disagreed with Staff's interpretation of the applicability of the rate impact cap to the costs related to the Pathway Project.[140] The Settlement Agreement proposes the Commission defer deciding any issues related to interpretation of § 40-2-125.5(5), C.R.S., and the scope of the "clean energy plan revenue rider" to Proceeding No. 21A-0141E. The Stipulation does not address this issue. We agree with the Settling Parties that issues regarding interpretation of §40-2-125.5(5), C.R.S., if any, are more appropriately considered within the 2021 ERP and CEP Proceeding and are not applicable to the instant Proceeding.

(1) CORE's Request for Directed Negotiations

134. In its SOP, CORE requests the Commission condition any approval of the Pathway Project on the requirement that the Company "engage in good-faith negotiations with interested utilities that serve Colorado electric customers and are willing and able to invest in joint ownership of the Power Pathway."[141] CORE asserts the Commission should consider including parameters "such as a timeline for study and negotiations, a notification and/or qualification requirement for interested utilities, appointment of Commission Staff or another third-party neutral monitor, and future reporting requirements for the Company and interested utilities" when approving a CPCN for the Pathway Project.[142]

135. The Settlement Agreement notes that the Company does not anticipate a joint ownership or partnership arrangement will materialize for the Pathway Project, but that if one

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[140] *See* Hg Ex. 111, Attachment AKJ-2_Joint Brief Re CEPR Public Service, CEO, CIEA, COSSA/SEIA, Interwest, the RMELC/CBCTC, and WRA (collectively, the "Joint Parties").

[141] CORE SOP, at p. 2.

[142] CORE SOP, at p. 8.

were to materialize, the Settling Parties agree that it is appropriate for the Company to make the appropriate filing with the Commission that would allow for Commission review and approval.[143]

136. The Commission declines to predicate approval of the Pathway Project as CORE requests. Requiring the Company to engage in good-faith negotiations prior to issuing a CPCN for this Project would needlessly delay and jeopardize the Pathway Project. As such, we adopt paragraph 30 of the Settlement Agreement.

(2) Competitive Solicitation for Building the Pathway Project

137. The Stipulating parties urge the Commission to consider conditioning any CPCN granted for segments with an in-service date of 2026 and beyond by requiring cost-effective regional transmission planning and competitive bidding.[144] According to the Stipulating parties, coordinated planning and competitive bidding for transmission will "right-size" the system needed, spread costs more broadly, and put downward competitive pressure on the transmission costs needed to meet the State's clean energy goals.[145]

138. In the Joint SOP, the parties refute the Partial Stipulation's approach to competitive solicitation.[146] They note that the Partial Stipulation "provides no basis in Colorado law for the Commission to impose processes" on coordinated transmission planning and competitive bidding processes for transmission facilities. *Id*. at p. 23. They contend that the Partial Stipulation approach ignores that this Project was appropriately planned in accordance with Public Service's FERC-approved Joint Open Access Transmission Tariff (as a local project)

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[143] Settlement Agreement, at ¶ 30.
[144] Partial Stipulation, at ¶ 7.
[145] Partial Stipulation, at ¶ 9.
[146] Public Service Joint SOP, at p. 24.

and that planning occurred through both the CCPG process as well as the CCPG 80x30 Task Force.[147]

139. The Commission acknowledges the substantial potential benefits that competitive solicitation could bring to transmission project development in the future. However, the Power Pathway Project faces significant time constraints to meet the proposed in-service dates. The Company needs to reduce emissions by 2030 and move quickly to capture currently available federal tax credits. We therefore decline to order the Company to use a competitive procurement or solicitation process for development and construction of the Power Pathway Project. The Commission declines to adopt the conditions regarding competitive solicitation as set forth by the Partial Stipulation.

(3) Reporting Requirements

140. The Settlement Agreement proposes the Company will file several Semi-Annual Progress Reports within this proceeding to detail progress and changes to the Project as it relates to this CPCN.[148] The Settling Parties agree the Company will file information regarding: monthly actual expenses incurred and monthly budgeted expenditures by activity for major expense categories; any modifications, by month, to subsequent forecasted expenditures for the remainder of the Project; a cumulative comparison of actual costs to estimated costs for the Project; an explanation of any material changes to the overall cost estimate for the Project; an explanation of any material changes to the installation schedule for the Project; an explanation of efforts to reduce costs; an overall Project progress exhibit that presents Project schedules and actual Project progress for major milestones including, but not limited to, land use permits from local

[147] *Id*. at 22-24.
[148] Settlement Agreement, at ¶ 25.

government(s), acquisition of property rights, major equipment procurements and purchases, and construction progress, testing, commissioning, and commercial operations; and a narrative statement of the overall status of the Project.

141. The Commission accepts these progress updates as outlined by the Settlement Agreement and expects these semi-annual reports beginning on November 15, 2022, and no later than 120 days thereafter. The Commission also expects that if a CPCN is triggered for the MVL Extension, Public Service will report on these same metrics for the extension, to commence with the first semi-annual report after the MVL Extension CPCN becomes unconditional.

(4) Other Terms

142. Unless specifically addressed and adopted above, the Commission does not adopt the remainder of the terms of the Settlement Agreement, and we do not adopt the terms of the Partial Stipulation. Thus, we grant the Motion to Approve the Settlement Agreement in part, and we deny the Motion for Approval of the Partial Stipulation.

II. ORDER

A. The Commission Orders That:

1. The Motion to Approve the Non-unanimous Comprehensive Settlement Agreement, filed by Public Service Company of Colorado (Public Service), Staff of the Public Utilities Commission the Colorado Energy Office, Interwest Energy Alliance, County of Pueblo, Colorado Independent Energy Association, Colorado Solar and Storage Association, the Solar Energy Industries Association, the Rocky Mountain Environmental Labor Coalition and Colorado Building and Construction Trades Council, AFL-CIO, and Western Resource Advocates on November 9, 2021, is granted in part, consistent with the discussion above.

2. The Joint Motion for Approval of Partial Stipulation, filed on November 9, 2021 by the Office of the Utility Consumer Advocate, the Colorado Energy Consumers Group, and Climax Molybdenum Company, is denied, consistent with the discussion above.

3. The Application for a Certificate of Public Convivence and Necessity for Colorado's Power Pathway 345 kV Transmission Project (Project or Pathway Project) filed by Public Service on March 2, 2021 (Application) is granted in part, consistent with the discussion above.

4. Public Service is granted a Certificate of Public Convenience and Necessity to construct and operate Colorado's Power Pathway 345 kV Transmission Project.

5. The expected maximum magnetic field and noise levels associated with the Pathway Project as set forth in the Application are reasonable.

6. Public Service is granted a Certificate of Public Convenience and Necessity to construct and operate the May Valley-Longhorn Extension (MVL Extension), subject to the condition that the MVL Extension be included in the final resource plan approved in Proceeding No. 21A-0141E.

7. The expected maximum magnetic field and noise levels associated with the MVL Extension as set forth in the Application are reasonable.

8. A Performance Incentive Mechanism conforming with the discussion above is adopted and is applicable to the Project and, in the event the MVL Extension receives an unconditional Certificate of Public Convenience and Necessity, is applicable to the MVL Extension.

9. Public Service shall file any compliance advice letter(s) to implement any tariff changes made necessary by this Decision, including the adoption of the Performance Incentive

Mechanism, within 20 days of the effective date of this Decision, on not less than 15 days' notice.

10. Public Service and Staff of the Commission shall file in this Proceeding, an update regarding the scope of work and approach to retaining an Owners Engineer as further described in the discussion above, within 90 days of the effective date of this Decision.

11. Consistent with the discussion above, Public Service shall file, as compliance filings in this Proceeding, Semi-Annual Progress Reports for the Project and if applicable, for the MVL Extension. The first Semi-Annual Progress Report shall be filed no later than November 15, 2022, and subsequent reports shall be filed no later than 120 days following the due date of the prior report. Semi-Annual Progress Reports shall continue to be filed until six months after all Project facilities, and if applicable, MVL Extension facilities, are placed in service.

12. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

13. This Decision is effective upon its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' DELIBERATIONS AND WEEKLY MEETINGS
February 11, 2022 and February 23, 2022.**

(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