**IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF VIRGINIA
RICHMOND DIVISION**

UNITED STATES OF AMERICA and the COMMONWEALTH OF VIRGINIA, Plaintiffs,	
v.	Civil Action No. 3:20-cv-177
VIRGINIA ELECTRIC AND POWER COMPANY (d/b/a DOMINION ENERGY VIRGINIA) Defendant.	COMPLAINT

The United States of America ("United States"), by authority of the Attorney General of the United States and on behalf of the United States Environmental Protection Agency ("EPA"), and the Commonwealth of Virginia, on behalf of the Virginia Department of Environmental Quality ("VADEQ") (collectively "Plaintiffs") file this Complaint and allege as follows:

INTRODUCTION

1. This is a civil action for assessment of civil penalties and injunctive relief brought against Defendant Virginia Electric and Power Company (d/b/a Dominion Energy Virginia) ("Defendant" or "Dominion") pursuant to the following statutes: (a) the Federal Water Pollution Control Act ("Clean Water Act" or "CWA") and the Virginia State Water Control Law ("SWCL") for violations of conditions and limitations of National Pollutant Discharge Elimination System ("NPDES") permits issued to Dominion at certain of Defendant's steam electric power generation facilities in Virginia and West Virginia; (b) the SWCL for unpermitted discharges of industrial waste or other waste to State waters via seeps at the Chesterfield Power Station Facility in violation of Va. Code § 62.1-44.5; and (c) the Emergency Planning and Community Right-to-Know Act

("EPCRA") and the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") for violations of the hazardous substance release notification requirements at Defendant's steam electric power generation facilities in Virginia and West Virginia.

JURISDICTION AND VENUE

2. This Court has jurisdiction over the subject matter of this action under Section 309(b) of the CWA, 33 U.S.C. § 1319(b), Section 109(c) of CERCLA, 42 U.S.C. § 9609(c), and 28 U.S.C. §§ 1331, 1345, and 1355. Pursuant to 28 U.S.C. § 1367(a), this Court has supplemental jurisdiction over the state law claims of the Commonwealth of Virginia because they are related to the federal law claims and form a portion of the same case or controversy.

3. Venue is proper in the Eastern District of Virginia pursuant to 28 U.S.C. §§ 1391(b)(2) and (c)(2) and 1395(a), as well as Section 309(b) of the CWA, 33 U.S.C. § 1319(b) and Section 109(c) of CERCLA, 42 U.S.C. § 9609(c), because it is the judicial district in which Defendant is located, is doing business, and in which a substantial part of the alleged violations in the Complaint occurred.

4. Notice of the action's commencement has been provided to the Commonwealth of Virginia and the State of West Virginia in accordance with Section 309(b) of the CWA, 33 U.S.C. § 1319(b).

DEFENDANT

5. Virginia Electric and Power Company (d/b/a Dominion Energy Virginia) is a corporation with its principal place of business in Richmond, Virginia. Virginia Electric Power Company is a wholly owned subsidiary of Dominion Energy, Inc.

6. During the time period relevant to the claims in this Complaint, Defendant owned and operated the facilities subject to this Complaint.

STATUTORY FRAMEWORK

I. Clean Water Act

Statutory Background

7. Section 301(a) of the CWA, 33 U.S.C. § 1311(a), prohibits the "discharge of any pollutant by any person" to waters of the United States, except, *inter alia*, in compliance with an NPDES permit issued by EPA or an authorized state pursuant to Section 402 of the CWA, 33 U.S.C. § 1342.

8. Section 502(5) of the CWA, 33 U.S.C. § 1362(5), defines "person" as, *inter alia*, an "individual, corporation, partnership, [or] association."

9. Section 502(12) of the CWA, 33 U.S.C. § 1362(12), defines the term "discharge of a pollutant" as, *inter alia*, "any addition of any pollutant to navigable waters from any point source."

10. Section 502(6) of the CWA, 33 U.S.C. § 1362(6), defines "pollutant" to include a wide range of materials, including solid waste, rock, sand, and industrial waste.

11. Section 502(14) of the CWA, 33 U.S.C. § 1362(14), defines "point source" as any "discernible, confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, [or] container . . . from which pollutants are or may be discharged."

12. Section 502(7) of the CWA, 33 U.S.C. § 1362(7), defines "navigable waters" as "the waters of the United States, including the territorial seas."

NPDES Permit Program

13. Under Section 402(a) of the CWA, 33 U.S.C. § 1342(a), EPA has the authority to issue an NPDES permit "for the discharge of any pollutant" to waters of the United States if "such discharge will meet . . . all applicable requirements" of the CWA and other conditions that the

permitting authority determines necessary to implement the CWA.

14. A state may administer its own NPDES permit program with EPA's approval. *See* 33 U.S.C. § 1342(b).

15. The Commonwealth of Virginia has been authorized by EPA to administer an NPDES program for regulating the discharges of pollutants to navigable waters within the state's jurisdiction. 40 Fed. Reg. 20129 (May 8, 1975). The Commonwealth of Virginia, through the State Water Control Board is authorized to issue, amend, revoke and enforce NPDES permits in the Commonwealth of Virginia in accordance with the SWCL. Va. Code § 62.1-44.15(5).

16. The State of West Virginia has been authorized by EPA to administer an NPDES program for regulating the discharges of pollutants to navigable waters within the state's jurisdiction. 47 Fed. Reg. 22363 (May 24, 1982). The West Virginia Department of Environmental Protection ("WVDEP") is authorized to issue NPDES permits in accordance with the West Virginia Water Pollution Control Act ("WPCA"). W. Va. Code § 22-11-8.

17. EPA's approval of Virginia's and West Virginia's programs does not affect its authority to enforce the CWA or to enforce a state-issued NPDES permit. *See* 33 U.S.C. § 1342(i).

18. A "permit" is "an authorization, license, or equivalent control document issued by EPA or an 'approved State' to implement the requirements of [the CWA]." 40 C.F.R. § 122.2 (definitions).

19. An NPDES permit typically contains, among other things, effluent limitations, water quality standards, monitoring and reporting requirements, standard conditions applicable to all permits, and special conditions where appropriate. *See* 40 C.F.R. §§ 122.41-122.50 (NPDES permit conditions).

20. Effluent limitations, as defined in Section 502(11) of the CWA, 33 U.S.C. § 1362(11), are restrictions on quantity, rate, and concentration of chemical, physical, biological,

and other constituents which are discharged from point sources. 33 U.S.C. § 1362(11); *see also* 9 VAC 25-31-10.

NPDES Stormwater Permits

21. Section 402(p) of the CWA, 33 U.S.C. § 1342(p), and 40 C.F.R. § 122.26(a)(1)(ii) require stormwater discharges associated with industrial activity to comply with all applicable provisions of Section 301 of the CWA, 33 U.S.C. § 1311.

22. Under EPA's regulations, any person who discharges or who proposes to discharge stormwater associated with industrial activity or small construction activity is required to apply for an individual permit or to seek coverage under a promulgated stormwater general permit. *See* 40 C.F.R. §§ 122.21(a), 122.26(c), 122.28, 123.25.

23. Pursuant to 40 C.F.R. § 122.26(b)(14)(vii), steam electric power generating facilities, including coal handling sites, are considered to be engaging in industrial activities.

24. Pursuant to 40 C.F.R. § 122.26(b)(14)(x), industrial activity for which associated stormwater discharges require a Section 402 permit includes construction activity that disturbs five acres or more of total land area. Construction activity includes "clearing, grading, and excavation."

Enforcement

25. Section 309(b) of the CWA, 33 U.S.C. § 1319(b), authorizes the United States to commence a civil action for appropriate relief, including a permanent or temporary injunction, against any person who violates any permit condition or limitation in a permit issued pursuant to Section 402 of the CWA, 33 U.S.C. § 1342.

26. Pursuant to Section 309(d) of the CWA, 33 U.S.C. § 1319(d), and EPA's 2013 and 2019 Civil Monetary Penalty Inflation Adjustment Rules, 78 Fed. Reg. 66643 (Nov. 6, 2013) and 84 Fed. Reg. 2056 (Feb. 6, 2019), codified at 40 C.F.R. § 19.4, any person who violates any condition or limitation contained in a NPDES permit issued pursuant to Section 402 of the CWA,

Lucas/Junis/Manes Cross Examination Exhibit No. 1

33 U.S.C. § 1342, shall be subject to a civil penalty not to exceed $37,500 per day for each violation that occurred after January 12, 2009 through November 2, 2015; and not to exceed $54,833 per day for each violation which takes place after November 2, 2015.

II. <u>The Virginia State Water Control Law</u>

27. It is a violation of the SWCL for any "person" to discharge "industrial wastes" or "other wastes" into "state waters" except in compliance with a Virginia NPDES permit. Va. Code § 62.1-44.5(A)(1).

28. In addition, it is a violation of the SWCL for any "person" to discharge "stormwater" into "state waters" from "land disturbing activities" except in compliance with a Virginia NPDES permit. Va. Code § 62.1-44.5(A)(5).

29. The SWCL defines "person" as "an individual, corporation, partnership, association, governmental body, municipal corporation, or any other legal entity." Va. Code § 62.1-44.3.

30. The SWCL defines "industrial waste" as "liquid or other wastes resulting from any process of industry, manufacture, trade, or business or from the development of any natural resources." Va. Code § 62.1-44.3.

31. The SWCL defines "other waste" as "decayed wood, sawdust, shavings, bark, lime, garbage, refuse, ashes, offal, tar, oil, chemicals, and all other substances except industrial wastes and sewage which may cause pollution in any state waters." Va. Code § 62.1-44.3.

32. The SWCL defines "state waters" as "all water, on the surface and under the ground, wholly or partially within or bordering the Commonwealth or within its jurisdiction, including wetlands." Va. Code § 62.1-44.3.

33. Va. Code § 62.1-44.15(10) authorizes the State Water Control Board to "adopt such regulations as it deems necessary to enforce the general water quality management program in . .

. the Commonwealth."

34. Va. Code § 62.1-44.23 authorizes Virginia to commence a civil action for injunctive relief to compel compliance with the terms or conditions of a valid NPDES permit and the SWCL. *See* Va. Code § 62.1-44.23.

35. "Except as otherwise provided in [the SWCL], any person who violates any provision of [the SWCL], or who fails, neglects, or refuses to comply with any order of the Board, or order of a court, issued as herein provided, shall be subject to a civil penalty not to exceed $32,500 for each violation within the discretion of the court. Each day of violation of each requirement shall constitute a separate offense." Va. Code § 62.1-44.32.

III. <u>EPCRA and CERCLA</u>

36. Section 329(7) of EPCRA, 42 U.S.C. § 11049(7), and Section 101(21) of CERCLA, 42 U.S.C. § 9601, each define a "person" as including a corporation.

37. Section 103(a) of CERCLA states that "[a]ny person in charge of . . . an . . . onshore facility shall, as soon as he has knowledge of any release. . . of a hazardous substance . . . in quantities equal to or greater than those determined pursuant to [section 102 of CERCLA], immediately notify the National Response Center [("NRC")]." 42 U.S.C. § 9603(a).

38. Section 102 of CERCLA, 42 U.S.C. § 9602, directs the Administrator of EPA to promulgate regulations designating hazardous substances and establishing reportable quantities for those hazardous substances. EPA's list of hazardous substances and reportable quantities is set forth at 40 C.F.R. § 302.4. Ammonia is included in this list.

39. Section 109(c) of CERCLA provides as follows:

> The President may bring an action in the United States district court for the appropriate district to assess and collect a penalty of not more than $25,000 per day for each day during which the violation (or failure or refusal) continues in the case of . . . (1) A violation of the notice requirements of section 9603(a) . . . of this title. . . . In the case of a second or subsequent violation (or failure or refusal), the amount of such penalty may be not more

than $75,000 for each day during which the violation (or failure or refusal) continues.

42 U.S.C. § 9609(c).

40. Section 302 of EPCRA, 42 U.S.C. § 11002, requires EPA to publish a list of extremely hazardous substances, and to identify a "reportable quantity" for each such substance. EPA's list of extremely hazardous substances and their reportable quantities is set forth at 40 C.F.R. Part 355, Appendices A and B. Ammonia is included in this list and has a reportable quantity of 100 pounds.

41. Section 304 of EPCRA, 42 U.S.C. § 11004, and the regulation set forth at 40 C.F.R. § 355.33, require the owner or operator of a facility at which a hazardous chemical is produced, used, or stored to notify certain government authorities when there is a release of a reportable quantity of an extremely hazardous substance or CERCLA hazardous substance. Specifically, Section 304(b) of EPCRA requires that the owner and operator immediately notify the State Emergency Response Commission ("SERC") of any State likely to be affected by the release and the emergency coordinator for the Local Emergency Planning Committee ("LEPC") for any area likely to be affected by the release. Additionally, Section 304(c) requires the owner/operator to submit, as soon as practicable, a written emergency follow-up notice updating the information required under Section 304(b).

42. Pursuant to Section 325(b)(3) of EPCRA, 42 U.S.C. § 11045(b)(3), and Section 109(c) of CERCLA, 42 U.S.C. § 9609(c), and EPA's 2013 and 2019 Civil Monetary Penalty Inflation Adjustment Rules, 78 Fed. Reg. 66643 (Nov. 6, 2013), and 84 Fed. Reg. 2056 (Feb. 6, 2019), codified at 40 C.F.R. § 19.4, any person who violates a reporting requirement of Section 304 of EPCRA, 42 U.S.C. § 11004, or Section 103 of CERCLA, 42 U.S.C. § 9603, shall be subject to a civil penalty not to exceed $37,500 per day for each violation that occurred after January 12, 2009 through November 2, 2015; and not to exceed $57,317 per day for each violation which takes

place after November 2, 2015.

GENERAL ALLEGATIONS

43. The Defendant is a "person" within the meaning of 33 U.S.C. § 1362(5), 42 U.S.C. § 9601, 42 U.S.C. § 11049(7), and Va. Code § 62.1-44.3.

44. At all relevant times, Defendant did business in Virginia and West Virginia.

45. Defendant owns and/or operates the steam electric power generation facilities and associated construction sites listed in Exhibits 1-6 that are subject to the allegations included in this Complaint (the "Facilities").

46. As a result of its power generation and construction operations at the Facilities, Defendant generates coal ash, wastewater, sediment, and other excess materials that are, or contain, various "pollutants" as that term is defined in 33 U.S.C. § 1362(6), 40 C.F.R. § 122.2, and 9 VAC 25-31-10. These pollutants include rock, sand, total ammonia nitrogen, total petroleum hydrocarbons, total recoverable manganese, total suspended solids, and other pollutants associated with coal ash discharge ("coal ash contact water"), which includes aluminum, antimony, arsenic, barium, beryllium, boron, cadmium, chloride, chromium III, chromium IV, cobalt, copper, iron, lead, mercury, molybdenum, nickel, selenium, silver, thallium, vanadium, and zinc.

CLAIM ONE FOR RELIEF
(Violations of NPDES Construction Stormwater Permits)

47. Plaintiffs reallege and incorporate by reference all other paragraphs of this Complaint as if fully set forth herein.

48. Defendant owns and/or operates the facilities engaged in construction activity that are subject to NPDES construction stormwater permits issued by Virginia listed in Exhibit 1.

49. Each of the NPDES construction stormwater permits identified in Exhibit 1 include, *inter alia*, conditions that require Defendant to implement a Stormwater Pollution Prevention Plan

("SWPPP"), install and maintain best management practices ("BMPs"), and conduct self-inspections at subject sites.

50. As set forth in Exhibit 1, Defendant has violated applicable NPDES construction stormwater permits, primarily due to failure to implement and maintain erosion control measures.

51. Each failure to adequately implement NPDES permit conditions identified in Exhibit 1 is a violation of the applicable NPDES permits issued under Section 402 of the CWA, 33 U.S.C. § 1342.

52. Defendant's violations of conditions contained in the applicable NPDES permits also constitute violations of Va. Code § 62.1-44.5.

53. Unless enjoined, Defendant's violations are likely to continue.

54. Pursuant to Section 309(b) of the CWA, 33 U.S.C. § 1319(b), and Va. Code § 62.1-44.23, Defendant is liable for injunctive relief.

55. Pursuant to Section 309(d) of the CWA, 33 U.S.C. § 1319(d), Defendant is liable for civil penalties of up to $37,500 per day for each violation occurring on or after January 12, 2009 through November 2, 2015, and $54,833 per day for each violation that occurred after November 2, 2015.

56. "Except as otherwise provided in [the SWCL], any person who violates any provision of [the SWCL], or who fails, neglects, or refuses to comply with any order of the Board, or order of a court, issued as herein provided, shall be subject to a civil penalty not to exceed $32,500 for each violation within the discretion of the court. Each day of violation of each requirement shall constitute a separate offense." Va. Code § 62.1-44.32.

CLAIM TWO FOR RELIEF
(Violations of NPDES Permit Effluent Limitations)

57. Plaintiffs reallege and incorporate by reference all other paragraphs of this

Complaint as if fully set forth herein.

58. Defendant owns and/or operates the power generation facilities that are subject to NPDES permits issued by Virginia or West Virginia listed in Exhibit 2.

59. The NPDES permits identified in Exhibit 2 include effluent limitations for, *inter alia*, total suspended solids, total petroleum hydrocarbons, total recoverable manganese, and total ammonia nitrogen. *See* Exhibit 2.

60. These NPDES permits also impose self-monitoring and self-reporting requirements, including submission to the permitting authorities of discharge monitoring reports ("DMRs"), which summarize discharge monitoring data and indicate non-compliance with permit limits.

61. Based on DMRs submitted to state permitting authorities and certified information provided by Defendant in response to information requests issued by EPA pursuant to Section 308 of the CWA, 33 U.S.C. § 1318, Defendant has exceeded effluent limitations in applicable NPDES permits on at least eight occasions. *See* Exhibit 2

62. Each exceedance identified in Exhibit 2 is a violation of the applicable NPDES permits issued under Section 402 of the CWA, 33 U.S.C. § 1342.

63. Defendant's discharges of pollutants in excess of effluent limitations contained in the applicable NPDES permits issued by Virginia also constitute violations of Va. Code § 62.1-44.5.

64. Unless enjoined, Defendant's violations are likely to continue.

65. Pursuant to Section 309(b) of the CWA, 33 U.S.C. § 1319(b), and Va. Code § 62.1-44.23, Defendant is liable for injunctive relief.

66. Pursuant to Section 309(d) of the CWA, 33 U.S.C. § 1319(d), Defendant is liable for civil penalties of up to $37,500 per day for each violation occurring on or after January 12,

2009 through November 2, 2015, and $54,833 per day for each violation that occurred after November 2, 2015.

67. "Except as otherwise provided in [the SWCL], any person who violates any provision of [the SWCL], or who fails, neglects, or refuses to comply with any order of the Board, or order of a court, issued as herein provided, shall be subject to a civil penalty not to exceed $32,500 for each violation within the discretion of the court. Each day of violation of each requirement shall constitute a separate offense." Va. Code § 62.1-44.32.

CLAIM THREE FOR RELIEF
(Violation of NPDES Permit Notice Condition)

68. Plaintiffs reallege and incorporate by reference all other paragraphs of this Complaint as if fully set forth herein.

69. Defendant owns and operates the Possum Point Facility in Virginia. In 2015, the Facility was subject to NPDES Permit VA0002071, issued in 2013 (the "2013 Possum Point Permit").

70. The 2013 Possum Point Permit authorized discharge from Outfall 005 Ash Pond E consistent with and according to the specific requirements and obligations set forth in Part II(J) and required advance notice to VADEQ before making certain changes to the facility that might affect discharges.

71. Discharges from Outfall 005 authorized by the 2013 Possum Point Permit occur by skimming effluent from the top of the impoundment pond after sufficient time is allowed for adequate settlement of pollutants.

72. From on or about March 25, 2015, through April 28, 2015, Defendant conducted dewatering activities intended to remove stored water from Ash Pond E to facilitate its eventual RCRA Coal Combustion Residuals ("CCR") closure (the "Ash Pond E Dewatering"). *See* Exhibit

3.

73. During this time period, Defendant's actions resulted in the net removal of an estimated volume of 27.5 million gallons of impoundment water from Ash Pond E by discharge at Outfall 005.

74. The Ash Pond E Dewatering was achieved by lowering the elevation of the decant structure of Outfall 005 by the removal of stoplogs.

75. This treatment structure alteration resulted in a potential increase in the nature or quantity of pollutants being discharged.

76. Defendant did not provide specific advance notification to VADEQ before commencing the Ash Pond E Dewatering.

77. Failure to provide specific advance notification to VADEQ precluded VADEQ from: (a) considering whether such proposed discharges would be protective of the receiving water quality and otherwise appropriate, and (b) exercising its authority as appropriate to require additional monitoring, treatment, or other precautions.

78. VADEQ modified the 2013 Possum Point Permit in January 2016 ("2016 Modified Permit") to allow for dewatering activities at Possum Point in preparation of meeting the requirements of the CCR closure rule. The 2016 Modified Permit included effluent limits for a greater number of pollutants.

79. Defendant's failure to provide specific advance notification of the Ash Pond E Dewatering to VADEQ is a violation of the applicable NPDES permit issued under Section 402 of the CWA, 33 U.S.C. § 1342.

80. Violating a condition in the applicable NPDES permit also constitutes violation of Va. Code § 62.1-44.5.

81. Unless enjoined, Defendant's violations are likely to continue.

82. Pursuant to Section 309(b) of the CWA, 33 U.S.C. § 1319(b), and Va. Code § 62.1-44.23, Defendant is liable for injunctive relief.

83. Pursuant to Section 309(d) of the CWA, 33 U.S.C. § 1319(d), Defendant is liable for civil penalties of up to $37,500 per day for each violation occurring on or after January 12, 2009 through November 2, 2015, and $54,833 per day for each violation that occurred after November 2, 2015.

84. "Except as otherwise provided in [the SWCL], any person who violates any provision of [the SWCL], or who fails, neglects, or refuses to comply with any order of the Board, or order of a court, issued as herein provided, shall be subject to a civil penalty not to exceed $32,500 for each violation within the discretion of the court. Each day of violation of each requirement shall constitute a separate offense." Va. Code § 62.1-44.32.

CLAIM FOUR FOR RELIEF
(Violation of NPDES Permit Discharge Prohibition)

85. Plaintiffs reallege and incorporate by reference all other paragraphs of this Complaint as if fully set forth herein.

86. Defendant owns and/or operates the facilities subject to NPDES permits issued by Virginia listed in Exhibit 4.

87. Each NPDES permit identified in Exhibit 4 prohibits discharges from the facility into state waters or that affect state waters, where the discharges are not authorized by a permit.

88. Exhibit 4 lists eight discharges of pollutants at Defendants' permitted facilities that were not authorized by the applicable permit.

89. Each unauthorized discharge of pollutants identified in Exhibit 4 is a violation of the applicable NPDES permit issued under Section 402 of the CWA, 33 U.S.C. § 1342.

90. Violating a condition in the applicable NPDES permit also constitutes violation of

Va. Code § 62.1-44.5.

91. Unless enjoined, Defendant's violations will continue.

92. Pursuant to Section 309(b) of the CWA, 33 U.S.C. § 1319(b), and Va. Code § 62.1-44.23, Defendant is liable for injunctive relief.

93. Pursuant to Section 309(d) of the CWA, 33 U.S.C. § 1319(d), Defendant is liable for civil penalties of up to $37,500 per day for each violation occurring on or after January 12, 2009 through November 2, 2015, and $54,833 per day for each violation that occurred after November 2, 2015.

94. "Except as otherwise provided in [the SWCL], any person who violates any provision of [the SWCL], or who fails, neglects, or refuses to comply with any order of the Board, or order of a court, issued as herein provided, shall be subject to a civil penalty not to exceed $32,500 for each violation within the discretion of the court. Each day of violation of each requirement shall constitute a separate offense." Va. Code § 62.1-44.32.

CLAIM FIVE FOR RELIEF
(VADEQ Only SWCL Violations)

95. Plaintiff VADEQ realleges and incorporates by reference all other paragraphs of this Complaint related to its VADEQ only SWCL Claims as if fully set forth herein. VADEQ makes the following allegations in support of alleged state only SWCL violations at the Chesterfield Power Station, as described in Exhibit 5.

96. On July 21, 2017, the Virginia Department of Game and Inland Fisheries ("DGIF") identified an area of groundwater seepage along the James River shoreline adjacent to Defendant's Chesterfield Power Station and subsequently notified both VADEQ and Defendant of the same.

97. Defendant investigated and later determined that the groundwater seepage identified by DGIF, which contained elevated concentrations of constituents and was daylighting

to the James River, originated from an existing coal pile ("Eastern Shoreline Seeps").

98. On May 11, 2018, Defendant self-reported to VADEQ its observation, at low tide, of a small area of groundwater seepage south of a coal ash impoundment ("Upper Ash Pond Seeps") at the Chesterfield Power Station, which contained elevated concentrations of constituents and was daylighting along the James River shoreline.

99. Defendant has taken actions, with VADEQ's direction and approval, to characterize and mitigate the Eastern Shoreline Seeps, including installation of a groundwater interceptor trench and collection system, which was completed in April 2019.

100. Each unauthorized discharge of pollutants without an NPDES permit is a violation of Va. Code § 62.1-44.5.

101. Unless enjoined, Defendant's violations will continue.

102. Pursuant to Va. Code § 62.1-44.23, Defendant is liable for injunctive relief.

103. "Except as otherwise provided in [the SWCL], any person who violates any provision of [the SWCL], or who fails, neglects, or refuses to comply with any order of the Board, or order of a court, issued as herein provided, shall be subject to a civil penalty not to exceed $32,500 for each violation within the discretion of the court. Each day of violation of each requirement shall constitute a separate offense." Va. Code § 62.1-44.32.

CLAIM SIX FOR RELIEF
(Federal Only EPCRA Violations)

104. Plaintiff the United States realleges and incorporates by reference all other paragraphs of this Complaint related to its federal Claims as if fully set forth herein.

105. At all times relevant to this Complaint, Defendant owned and operated the Bellemeade Power Station in Richmond, Virginia ("Bellemeade") and the Mt. Storm Power Station in West Virginia ("Mt. Storm") that are the subject of this action within the meaning of

Section 304 of EPCRA, 42 U.S.C. § 11004. *See* Exhibit 6.

106. The Bellemeade and Mt. Storm facilities are "facilities" within the meaning of Section 329(4) of EPCRA, 42 U.S.C. § 11049(4).

107. The Bellemeade and Mt. Storm facilities produce, use, or store ammonia, which is an extremely hazardous substance within the meaning of Section 329(3) of EPCRA, 42 U.S.C. § 11049(3).

108. Ammonia has a reportable quantity of 100 pounds. 40 C.F.R. § 302.4; 40 C.F.R. Part 355, Appendices A and B.

109. On November 26, 2015, the Bellemeade Facility released at least 220 pounds of ammonia into the environment (the "Bellemeade Release").

110. Defendant did not immediately report the Bellemeade Release to the SERC or LEPC, but rather reported the Release to the respective authorities after four days and 15 hours.

111. On March 15, 2017, the Mt. Storm Facility released at least 383 pounds of ammonia into the environment (the "Mt. Storm Release").

112. Defendant did not immediately report the Mt. Storm Release to the SERC or LEPC, but rather reported the Release to the respective authorities after over 13 hours.

113. Pursuant to Section 304(b) of EPCRA, 42 U.S.C. § 11004, and the regulation set forth at 40 C.F.R. Part 355, Subpart C, Defendant was required to immediately notify the SERC and the LEPC of a release equal to or greater than the reportable quantity of any EPCRA extremely hazardous substance or CERCLA hazardous substances.

114. Each failure to provide timely notification of these releases described above is a separate violation of Section 304(b) of EPCRA, 42 U.S.C. § 11004(b).

115. Pursuant to Section 325(b)(3) of EPCRA, 42 U.S.C. § 11045(b)(3), Defendant is liable for civil penalties of up to $37,500 per day for each violation for all violations occurring on

or after January 12, 2009 through November 2, 2015, and $57,317 per day for each violation that occurred after November 2, 2015.

CLAIM SEVEN FOR RELIEF
(Federal Only CERCLA Violations)

116. Plaintiff the United States realleges and incorporates by reference all other paragraphs of this Complaint related to its federal claims as if fully set forth herein.

117. At all times relevant to this Complaint, Defendant owned and operated the Bellemeade and Mt. Storm facilities within the meaning of Section 103 of CERCLA, 42 U.S.C. § 9603. *See* Exhibit 6.

118. The Bellemeade and Mt. Storm facilities are “onshore facilities” within the meaning of Section 101(18) of CERCLA, 42 U.S.C. § 9601(18), and 40 C.F.R. § 302.3.

119. The Bellemeade and Mt. Storm facilities produce, use, or store ammonia, which is a hazardous substance within the meaning of CERCLA Section 103(c), 42 U.S.C. § 9603(c).

120. Ammonia has a reportable quantity of 100 pounds. 40 C.F.R. § 302.4.

121. As summarized in Exhibit 6, and described above, Defendant failed to immediately notify the NRC of the Bellemeade Release and the Mt. Storm Release of reportable quantities of ammonia.

122. Each failure to immediately notify the NRC of these releases is a separate violation of Section 103(a) of CERCLA, 42 U.S.C. § 9603(a).

123. Pursuant to Section 109 of CERCLA, 42 U.S.C. § 9609(a), Defendant is liable for civil penalties of up to $37,500 per day for each violation for all violations occurring on or after January 12, 2009 through November 2, 2015, and $57,317 per day for each violation that occurred after November 2, 2015.

PRAYER FOR RELIEF

WHEREFORE, Plaintiffs, the United States of America and the Commonwealth of Virginia respectfully pray that this Court:

1. Permanently enjoin Defendant from discharging pollutants except as expressly authorized by the CWA and the limitations and conditions of applicable NPDES permits.

2. Order Defendant to take all necessary steps to comply with the CWA, SWCL, EPCRA/CERCLA, and the implementing regulations for those statutes, as well as with the limitations and conditions of the applicable NPDES permits.

3. Assess civil penalties against Defendant up to $37,500 per day for each violation of the CWA that occurred on or after January 12, 2009 through November 2, 2015, and up to $54,833 per day for each violation of the CWA that occurred after November 2, 2015.

4. Assess civil penalties against Defendant of up to $32,500 per day for each day of violation in the Commonwealth of Virginia pursuant to Va. Code § 62.1-44.32.

5. Assess civil penalties against Defendant up to $37,500 per day for each violation of the EPCRA that occurred on or after January 12, 2009 through November 2, 2015, and up to $57,317 per day for each violation of the EPCRA that occurred after November 2, 2015.

6. Assess civil penalties against Defendant up to $37,500 per day for each violation of the CERCLA that occurred on or after January 12, 2009 through November 2, 2015, and up to $57,317 per day for each violation of the CERCLA that occurred after November 2, 2015.

7. Grant such other relief as the Court may deem appropriate.

Respectfully submitted,

FOR THE UNITED STATES OF AMERICA

/s/
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Environment and Natural Resources Division

/s/
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FOR THE UNITED STATES OF AMERICA

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FOR THE COMMONWEALTH OF VIRGINIA

/s/

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Counsel for the Commonwealth of Virginia

EXHIBIT 1
Violations of NPDES Construction Stormwater Permits

Dominion Site	Permit Number	Violation Description
Bremo Pond Closure	VAR-10H875	VADEQ inspection report dated 4/4/16 identifies deficiencies with the operation and/or maintenance of BMPs.
Louisa Solar	VAR-10I424	VADEQ inspection reports dated 9/27/16 and 10/6/16 identify deficiencies with the operation and/or maintenance of BMPs.
Liberty Station	VAR-108818	EPA report dated 6/14/16 identifies deficiencies with the operation and/or maintenance of BMPs and with the corrective action implementation.
Scott Solar	VAR-10I027	VADEQ inspection reports dated 8/11/16 and 9/29/16 and 12/12/16 identify deficiencies with the operation and/or maintenance of BMPs and with the SWPP.
Brunswick Power Station	VAR100578	Dominion self-inspection reports pertaining to "Location A" identify deficiencies with the operation and/or maintenance of BMPs and with the corrective action implementation from 1/6/14-5/12/15.
Brunswick Power Station	VAR100578	Dominion self-inspection reports pertaining to "Location B" identify deficiencies with the operation and/or maintenance of BMPs and with the corrective action implementation from 1/6/14-12/29/14.
Brunswick Power Station	VAR100578	Dominion self-inspection reports pertaining to "Location C" identify deficiencies with the operation and/or maintenance of BMPs and with the corrective action implementation from 8/29/14-4/10/15.
Hollymead	VAR-100076	From July through September of 2014, inspection reports show multiple Corrective Actions that are not timely implemented, BMP compliance concerns and that the site is not in compliance with the SWPPP.

EXHIBIT 2
Violations of NPDES Permit Effluent Limitations

Dominion Site	Permit Number	Violation Description	Date	Limit	Result
Chesapeake Energy Center	VA0004081	Effluent Violation – Total Suspended Solids Outfall 002	04/06/2016	50 mg/l	56 mg/l
Chesterfield Power Station	VAG830470	Effluent Violation – Total Petroleum Hydrocarbons Outfall 001	04/07/2015	15 mg/l	60 mg/l
Chesterfield Power Station	VA0004146	Permit Limit-Total Recoverable Selenium-Quantification Level	03/10/2017		
Clover Power Station	VA0083097	Effluent Violation – Total Recoverable Manganese Outfall 009	12/12/2013	50 ug/l	59.65 ug/l
Clover Power Station	VA0083097	Effluent Violation – Total Suspended Solids Outfall 002	3/31/2014	50 mg/l	176.5 mg/l
Mt. Storm Power Station	WV0005525	Effluent Violation – Total Ammonia Nitrogen Outfall 421	3/23/2016	15 mg/l	24.5 mg/l
Mt. Storm Power Station	WV0005525	Effluent Violation – Total Ammonia Nitrogen Outfall 421	3/23/2016	30 mg/l	36.1 mg/l
Altavista Power Station	VA0083402	Effluent Violation – pH Outfall 001	3/10/2016	9.0	9.73

EXHIBIT 3
Violation of NPDES Permit Notice Condition

Dominion Site	Permit Number	Violation Description
Possum Point Power Station	VA0002071	Failure to notify prior to initiating permitted dewatering of Pond E-discharges from Pond E were permitted but Dominion failed to properly provide advance notice to VADEQ prior to the March 25, 2015 through April 28, 2015 dewatering activities intended to remove stored water from coal ash pond E to facilitate it eventual closure, as required by Part II(J) of the 2013 Possum Point NPDES Permit

EXHIBIT 4
Violation of NPDES Permit Discharge Prohibition

Dominion Site	Permit Number	Violation Description
Possum Point Power Station	VA0002071	Unpermitted/Unauthorized discharges from Pond C through point source from at least March 2014 through May 2015
Chesterfield Power Station	VA0004146	On or about July 5, 2017, Defendant experienced an unpermitted discharge of an estimated 277,000 gallons of liquid from the Coal Pile Runoff Pond, which consisted of stormwater overflow comingled with coal fines.
Clover Power Station	VA0083097	Unpermitted discharge of stormwater comingled with coal fines from coal pile/limestone runoff basin, May 19, 2018.
Bath County Power station	VA0053317	Unpermitted discharge of an estimated 3 gallons of hydraulic oil on August 15, 2016.
Chesterfield Power Station	VA0004146	Unpermitted discharge of approximately 5 gallons of hydraulic fluid on January 5, 2018.
Chesterfield Power Station	VA0004146	Unpermitted discharge of turbine lube oil as observed on October 25, 26 and November 1, 2017.
Chesterfield Power Station	VA0004146	Unpermitted discharge of stormwater comingled with coal fines from Coal Pile Runoff Pond, September 28 and 29, 2016.
Chesterfield Power Station	VA0004146 VWP10-1787	Unauthorized discharges of sediment from construction activities during August 2017.

EXHIBIT 5
VADEQ Only SWCL Violations

Dominion Site	Statutory Provision	Violation Description	Receiving Water
Chesterfield Power Station	Va. Code § 62.1-44.5	Groundwater seepage daylighting along the James River shoreline which originated from the coal pile area, first identified on July 21, 2017.	James River
Chesterfield Power Station	Va. Code § 62.1-44.5	Groundwater seepage daylighting along the James River shoreline which originated from the coal ash impoundment, first reported on May 11, 2018.	James River

EXHIBIT 6
Federal Only EPCRA and CERCLA Violations

Mt. Storm CERCLA/EPCRA

March 15, 2017 Mt. Storm Power Station Release of Ammonia	
CERCLA 103	Failure to immediately notify NRC of Release
EPCRA 304(a)	Failure to immediately notify SERC of Release
EPCRA 304(a)	Failure to immediately notify LEPC of Release

Bellemeade Power Station CERCLA/EPCRA

November 26, 2015 Bellemeade Power Station Release of Ammonia	
CERCLA 103	Failure to immediately notify NRC of Release
EPCRA 304(a)	Failure to immediately notify SERC of Release
EPCRA 304(a)	Failure to immediately notify LEPC of Release

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF VIRGINIA

UNITED STATES OF AMERICA and the COMMONWEALTH OF VIRGINIA, Plaintiffs, v.	)	
VIRGINIA ELECTRIC AND POWER COMPANY (d/b/a DOMINION ENERGY VIRGINIA) Defendant.	)	CONSENT DECREE

TABLE OF CONTENTS

I. BACKGROUND

A. Concurrent with the Date of Lodging of this Consent Decree, Plaintiffs, the United States of America, on behalf of the United States Environmental Protection Agency ("EPA"), and the Commonwealth of Virginia, by and through the Department of Environmental Quality ("DEQ" or the "State") have filed a Complaint in this action against Defendant Virginia Electric and Power Company (d/b/a Dominion Energy Virginia) ("Defendant" or "Dominion") pursuant to the following statutes: (1) Sections 309(b) and (d) of the Federal Water Pollution Control Act ("Clean Water Act" or "CWA"), 33 U.S.C. §§ 1319(b), and (d); and, (2) the Virginia State Water Control Law ("SWCL"), Va. Code §§ 62.1-44.2 through 62.1-44.34:28. The Complaint alleges that the Defendant has violated the CWA and SWCL, including conditions and limitations of National Pollutant Discharge Elimination System ("NPDES") permits issued to them by the State pursuant to the EPA-approved permit program under Section 402 of the CWA, 33 U.S.C. § 1342, and Va. Code § 62.1-44.15. The Complaint also alleges State only violations under the SWCL at one of Defendant's Facilities. Additionally, the Complaint alleges Federal only violations at two of Defendant's Facilities, under Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), 42 U.S.C. § 9603, and Section 304 of the Emergency Planning and Community Right-to-Know Act ("EPCRA"), 42 U.S.C. § 11004, by failing to immediately report releases of reportable quantities ("RQ") of a CERCLA hazardous substance and EPCRA extremely hazardous substance ("EHS") into the environment.

B. Defendant does not admit any liability to the United States, the State, any governmental body, or any other organization or person arising out of the transactions or occurrences alleged in the Complaint nor does Defendant admit any fact or legal conclusion alleged in the Complaint.

C. Defendant, with the assistance of an environmental management system ("EMS") consultant ("EMS Consultant"), has developed a companywide EMS, embodied in an EMS Manual, which Defendant submitted to Plaintiffs on February 23, 2018. Plaintiffs reviewed the EMS Manual and supporting documents, and EPA, after consultation with the State, notified Defendant that the EMS Manual was consistent with EPA's "Compliance Focused Environmental Management System Enforcement Agreement Guidance" ("EPA EMS Guidance") (Appendix A).

D. Specifically, the EMS Manual was prepared in reliance on a Third-Party EMS Gap Analysis, which was submitted to Plaintiffs for review in the form of a Gap Analysis Report for Defendant's Power Generation business segment on February 23, 2018.

E. The Gap Analysis Report contained: (i) a summary of the internal environmental audit process, including any obstacles encountered in performing such audits; (ii) detailed findings on Defendant's environmental management and compliance practices and processes, including the basis for each finding and each area of concern identified; (iii) identification of any areas of concern addressed during the audit; and (iv) recommendations for resolving any area of concern or steps necessary to ensure that Defendant's environmental policies and practices satisfy the requirements of the EPA EMS Guidance. The Gap Analysis was prepared to evaluate if Defendant's current EMS conformed with EPA's EMS Guidance, was properly developed, implemented, and maintained, and identify any areas for improvement.

F. Additionally, Defendant has a long-standing Internal Environmental Audit

Program ("IEAP"), which is regularly updated, most recently in December 2017. The IEAP was developed to provide a systematic, and periodic review of the status of environmental regulatory compliance at all Defendant's facilities and is designed to conform to Performance Standards included in the Board of Environmental Health and Safety Auditors Certification, "Standards for the Professional Practice of Environmental, Health, and Safety Auditing."

G. Following episodic releases of ammonia to the air at Defendant's Bellemeade Power Station on November 26, 2015 and Mt. Storm Power Station on March 15, 2017, Defendant updated its EPCRA Release Standard Operating Procedures and related incident reporting procedures. Defendant further conducted facility-specific training on EPCRA release reporting obligations, which included specific focus on ammonia operations associated with nitrogen oxide air pollution control systems. Defendant submitted its EPCRA Release SOPs to EPA.

H. On July 21, 2017, the Virginia Department of Game and Inland Fisheries ("DGIF") identified an area of groundwater seepage along the James River shoreline adjacent to Defendant's Chesterfield Power Station and subsequently notified both DEQ and Defendant of the same. Defendant investigated and later determined that the groundwater seepage identified by DGIF, which contained elevated concentrations of constituents and was daylighting to the James River, originated from an existing coal pile ("Eastern Shoreline Seeps"). In addition, on May 11, 2018, Dominion self-reported to DEQ its observation, at low tide, of a small area of groundwater seepage south of a coal ash impoundment ("Upper Ash Pond Seep") at the Chesterfield Power Station, which contained elevated concentrations of constituents and was daylighting along the James River shoreline.

I. Dominion has taken actions, with DEQ's direction and approval, to characterize and mitigate the Eastern Shoreline Seeps, including installation of a groundwater interceptor trench and collection system. The Upper Ash Pond is subject to closure by removal pursuant to a DEQ solid waste permit, which would include any required groundwater corrective action.

J. DEQ is the regulatory entity addressing the Eastern Shoreline Seeps and Upper Ash Pond Seep, solely under State law.

K. On April 15, 2016, EPA issued to Defendant an Information Request under Section 308 of the CWA, 33 U.S.C. § 1318, concerning activities at Defendant's Possum Point Facility. Defendant provided numerous responsive documents to the request. Subsequently, EPA and Defendant had several meetings and discussions about the responses, and a second 308 Information Request was issued to Defendant on January 5, 2017. EPA, Defendant and DEQ held multiple meeting and discussions, exchanged documents and information, and ultimately reached a resolution to the alleged violations contained in the Complaint, which is embodied in this Consent Decree.

L. The Parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated by the Parties in good faith and will avoid litigation among the Parties, and that this Consent Decree is fair, reasonable, and in the public interest.

NOW, THEREFORE, with the consent of the Parties, IT IS HEREBY ADJUDGED, ORDERED, AND DECREED as follows:

II. JURISDICTION AND VENUE

1. This Court has jurisdiction over the Parties and over the subject matter of this action, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367; Section 309(b) of the Clean Water

Act, 33 U.S.C. § 1319(b); Section 109 of CERCLA, 42 U.S.C. § 9609; and Section 325 of EPCRA, 42 U.S.C. § 11045.

2. The Parties agree that venue is proper in the Eastern District of Virginia pursuant to 28 U.S.C. §§ 1391(b) and (c) and 1395(a), as well as Section 309(b) of the Clean Water Act, 33 U.S.C. § 1319(b) and Section 109(c) of CERCLA, 42 U.S.C. § 9609(c).

3. For purposes of this Consent Decree, or any action to enforce this Consent Decree, Defendant consents to the Court's jurisdiction over this Consent Decree and consents to venue in this judicial district.

4. For purposes of this Consent Decree, Defendant agrees that the Complaint states claims upon which relief may be granted pursuant to Sections 301 and 402 of the CWA, 33 U.S.C. §§ 1311 and 1342, Section 109 of CERCLA, 42 U.S.C. § 9609, Section 325 of EPCRA, 42 U.S.C. § 11045, and Virginia Code §§ 62.1-44.2 through 62.1-44.34.28.

III. APPLICABILITY

5. The provisions of this Consent Decree apply to and are binding upon the United States, the State, Defendant, and Defendant's successors and/or assigns, except as otherwise set forth herein.

6. Defendant hereby agrees that it shall be bound to perform duties scheduled to occur by this Consent Decree prior to the Effective Date. In the event the United States withdraws or withholds consent to this Consent Decree before entry, or the Court declines to enter this Consent Decree, then the preceding requirement to perform duties scheduled to occur before the Effective Date shall terminate.

7. No transfer of ownership or operation of any Facility, or any portion thereof,

whether in compliance with the procedures of this Paragraph or otherwise, shall relieve Defendant of its obligation to ensure that the terms of the Consent Decree are implemented. From the date of lodging of this Consent Decree until its termination, at least thirty (30) Days prior to such transfer, Defendant shall provide a copy of this Consent Decree to the proposed transferee and shall simultaneously provide written notice of the prospective transfer, together with a copy of the proposed written agreement, to the State, EPA, the United States Attorney for the Eastern District of Virginia, and the United States Department of Justice, in accordance with Section XV of this Consent Decree (Notices). Any attempt to transfer ownership or operation of any Facility, or any portion thereof, without complying with this Paragraph constitutes a violation of this Consent Decree. In the event of any such transfer of ownership or other interest, neither Defendant nor the transferee will be required to undertake any further EMS-related or IEAP-related obligations with respect to the transferred Facility, but Defendant will not be released from other obligations of this Consent Decree unless: (i) EPA, after consultation with the State, determines that the transferee has the technical and financial ability to assume these obligations and liabilities; (ii) the United States and State have agreed in writing to release Defendant from the obligations and liabilities; (iii) the United States, State and the transferee have jointly moved to substitute the transferee as Defendant to this Consent Decree; and (iv) the Court has approved the substitution. The transferee shall apply for modification and/or transfer of any applicable NPDES Permit under applicable law.

8. In any action to enforce this Consent Decree, Defendant shall not raise as a defense the failure by any of its officers, directors, employees, agents, or contractors to take any actions necessary to comply with the provisions of this Consent Decree.

IV. DEFINITIONS

9. Terms used in this Consent Decree that are defined in the Act or in regulations promulgated pursuant to the Act shall have the meanings assigned to them in the Act or such regulations, unless otherwise provided in this Consent Decree. Whenever the terms set forth below are used in this Consent Decree, the following definitions shall apply:

a. "Applicable Law" shall mean the Clean Water Act ("CWA"), Virginia's State Water Control Law ("SWCL"), and relevant implementing regulations.

b. "Coal Ash Impoundment Facility" shall mean the Bremo, Chesapeake Energy Center, Chesterfield, and Possum Point Fixed Facilities.

c. "Complaint" shall mean the complaint filed by the United States and the State in this action concurrent with the lodging of this Consent Decree.

d. "Consent Decree" or "Decree" or "CD" shall mean this Decree and all appendices attached hereto.

e. "Daily Violation" shall mean (i) any exceedance of a maximum daily discharge limitation, as determined under applicable state or federal law, for any parameters set forth in NPDES permits applicable to any Facilities, which is identified by a DMR Sample, or (ii) any failure to attain a minimum daily discharge limitation for pH set forth in NPDES permits or, alternatively, compliance orders applicable to any Facilities, as determined under applicable state or federal law, which is identified by a DMR Sample.

f. "Day" or "day" shall mean a calendar day unless expressly stated to be a business day. In computing any period of time under this Consent Decree, where the last day would fall on a Saturday, Sunday, or federal holiday, the period shall run until the close of business of the next business day, except as otherwise provided in Paragraph 50.

g. "Defendant" or "Dominion" shall mean Virginia Electric and Power Company (d/b/a Dominion Energy Virginia).

h. "Discharge Monitoring Report Sample" or "DMR Sample" shall mean a sample taken in accordance with approved test procedures under 40 C.F.R. Part 136.

i. "Effective Date" shall be the date upon which this Consent Decree is entered by the Court or a motion to enter this Consent Decree is granted, whichever occurs first, as recorded on the Court's docket.

j. "Effluent Limit Violation" shall mean a Daily Violation or a Monthly Violation.

k. "EMS Audit" shall mean the audit conducted by the EMS Auditor pursuant to Paragraph 27 of this Consent Decree.

l. "EMS Auditor" shall mean the independent third-party environmental consultant approved by EPA, in consultation with the State, pursuant to Paragraphs 25 and 26 of this Consent Decree, who shall be contracted by Defendant to conduct the EMS Audit pursuant to this Consent Decree.

m. "EMS Audit Report" shall mean the report developed by the EMS Auditor after completion of the EMS Audit pursuant to Paragraph 27 of this Consent Decree.

n. "EMS Consultant" shall mean the independent third-party environmental consultant previously approved by EPA to perform the Gap Analysis and prepare the EMS Manual, which was approved by EPA, after consultation with the State.

o. “EMS Manual” shall mean the document that describes and documents the integrated EMS developed for the Defendant, which was fully implemented by the Power Generation business segment as of January 1, 2019, and has been approved by EPA.

p. “Environmental Audit Report” or “EA Report” shall mean the report developed by the Environmental Audit Consultant after completion of the Environmental Audit pursuant to Paragraph 32 of this Consent Decree.

q. “Environmental Audit Consultant” or “EA Consultant” shall mean the independent third-party environmental consultant approved by EPA, in consultation with the State, pursuant to Paragraphs 29 and 30 of this Consent Decree, who shall be contracted by Defendant to conduct the Third-Party Environmental Audit pursuant to this Consent Decree.

r. “Environmental Management System” or “EMS” refers to the integrated environmental compliance system created by Defendant and its EMS Consultant and approved by EPA as described in Section I, Paragraphs C, D and E, to standardize and formalize practices and programs used to maintain, track, and improve environmental performance.

s. “EPA” shall mean the United States Environmental Protection Agency and any of its successor departments or agencies.

t. “EPCRA Release Standard Operating Procedures” or “Release SOPs” shall mean the EPCRA Facility-specific SOPs relating to training and compliance obligations under Section 103 of CERCLA and Section 304 of EPCRA, as described in Paragraphs 36-41.

u. “EPCRA Facility” shall mean the Defendant’s Mount Storm, West Virginia, Facility.

v. “Facility” refers to a Fixed Facility, EPCRA Facility and Stormwater Facility, as used in this Consent Decree.

w. “Fixed Facility” shall mean the current or former power generation asset locations and associated or contiguous operations identified in Appendix B to this Consent Decree.

x. “Monthly Violation” shall mean any exceedance, as determined by a DMR Sample, of an average monthly discharge limitation for any parameters set forth in NPDES permits or, alternatively, compliance orders applicable to any Facility.

y. “NOVs” shall mean, for violations or any noncompliance that may impact water quality, notices of violation under Applicable Law.

z. “NPDES” shall mean the National Pollutant Discharge Elimination System defined in 40 C.F.R. § 122.2, applicable State regulations and any state-issued NPDES permit.

aa. “Paragraph” shall mean a portion of this Consent Decree identified by an Arabic numeral.

bb. “Parties” shall mean the United States, the State, and Defendant.

cc. “Power Generation business segment” or “PGBS” shall mean Defendant’s business organizations that operate electric power generating stations, not including nuclear power stations, in Virginia as well as their Virginia based construction locations subject to the CWA or SWCL. At a minimum, PGBS shall include Fixed Facilities and Stormwater Facilities.

dd. "Section" shall mean a portion of this Consent Decree identified by a Roman numeral.

ee. "State" shall mean the Commonwealth of Virginia.

ff. "Stormwater Facility" shall mean an operation of Defendant's Power Generation business segment in Virginia typically consisting of construction activities that require a stormwater NPDES Permit.

gg. "Third-Party Environmental Audit" or "Environmental Audit" or "EA" shall mean the EA required by Paragraphs 31-33 of this Consent Decree.

hh. "United States" shall mean the United States of America, acting on behalf of EPA.

V. CIVIL PENALTY

10. Within 30 Days after the Effective Date of this Consent Decree, Defendant shall pay a total of $1,400,000 as a civil penalty to the United States and the State.

11. $410,000 of the civil penalty shall be paid to the United States and $990,000 of the civil penalty shall be paid to the Commonwealth of Virginia.

12. Defendant shall make any payments to the United States required by this Consent Decree at https://www.pay.gov to the U.S. Department of Justice account, in accordance with instructions provided to Defendant by the Financial Litigation Unit ("FLU") of the United States Attorney's Office for the Eastern District of Virginia after the Effective Date. The payment instructions provided by the FLU shall include a Consolidated Debt Collection System ("CDCS") number, which Defendant shall use to identify all payments required to be made in accordance with this Consent Decree. The FLU will provide the payment instructions to:

Amanda B. Tornabene
Vice President, Environmental Services
Dominion Energy Services, Inc.
5000 Dominion Boulevard
Glen Allen, VA 23060
Amanda.b.tornabene@dominionenergy.com

and

Clay T. Burns
Senior Counsel, Law Department
Dominion Energy Services, Inc.
120 Tredegar St.
Richmond, VA 23219
clay.t.burns@dominionenergy.com

on behalf of Defendant. Defendant may change the individual to receive payment instructions on its behalf by providing written notice of such change to the United States in accordance with Section XV (Notices). At the time of payment, Defendant shall send notice of payment to: (i) EPA via email at CINWD_AcctsReceivable@epa.gov AND via regular mail at U.S. EPA Cincinnati Finance Office, MS: WG-32B26 Martin Luther King Drive, Cincinnati, Ohio 45268; (ii) EPA via email to the U.S. EPA Regional Hearing Clerk at R3_Hearing_Clerk@epa.gov; (iii) the United States via email or regular mail in accordance with Section XV (Notices); and (iv) the State in accordance with Section XV (Notices). Such notice shall state the Defendant's name, street/P.O. Box address, email address and telephone number; the name of the case; the docket number or civil action number of the case; the Consolidated Debt Collection System ("CDCS") Number and DOJ case number 90-5-1-1-11859; the amount of the payment; and the method of payment.

13. Defendant shall make payment to the Commonwealth of Virginia under this Section by certified or cashier's check made payable to the "Treasurer of Virginia." Payment

shall be mailed to: Receipts Control, Department of Environmental Quality, PO Box 1104, Richmond, Virginia 23218.

14. Defendant shall not deduct any penalties paid under this Consent Decree pursuant to this Section or Section IX (Stipulated Penalties) in calculating its federal, state, or local income tax.

VI. COMPLIANCE REQUIREMENTS

15. This Consent Decree in no way affects or relieves Defendant of its responsibility to comply with applicable federal, state, and local laws, regulations, and permits.

16. Defendant shall perform the work required by this Consent Decree in compliance with the requirements of all applicable federal, state, and local laws, regulations, and permits. This Consent Decree shall not be considered as a permit issued pursuant to any federal, state, or local statute or regulation.

17. Approval of Deliverables. Except for the State only approvals described in Paragraphs 36 and 37 of this CD, after review of any plan, report, or other item that is required to be submitted and approved pursuant to this Consent Decree, EPA, after consultation with the State, shall in writing: (a) approve the submission; (b) approve the submission with specified conditions; (c) approve part of the submission and disapprove the remainder; or (d) disapprove the submission.

18. If the submission is approved pursuant to Paragraph 17(a), Defendant shall take all actions required by the plan, report, or other document, in accordance with the schedules and requirements of the plan, report, or other document, as approved. If the submission is conditionally approved or approved only in part, pursuant to Paragraph 17(b) or 17(c), Defendant

shall, upon written direction from EPA, after consultation with the State, take those actions required by the approved plan, report, or other item that EPA, after consultation with the State, determines are technically severable from any disapproved portions, subject to Defendant's right to dispute the specified conditions or EPA's disapproval of the disapproved portions, under Section XI of this Consent Decree (Dispute Resolution).

19. If the submission is disapproved in whole or in part pursuant to Paragraph 17(c) or 17(d), Defendant shall, within 45 Days of receipt of disapproval or within such other timeframe or upon such other schedule as the Parties agree to in writing, correct all deficiencies and resubmit the plan, report, or other item, or disapproved portion thereof, for approval, in accordance with the preceding Paragraphs. If the resubmission is approved in whole or in part, Defendant shall proceed in accordance with the preceding Paragraph.

20. Any stipulated penalties applicable to the original submission, as provided in Section IX of this Consent Decree (Stipulated Penalties), shall accrue during the 45-Day period or other specified period, but shall not be payable unless the resubmission is untimely or is materially disapproved in whole or in part; provided that, if the original submission was so deficient as to constitute a material breach of Defendant's obligations under this Consent Decree, the stipulated penalties applicable to the original submission shall be due and payable notwithstanding any subsequent resubmission.

21. If a resubmitted plan, report, or other item, or portion thereof, is disapproved in whole or in part, EPA, after consultation with the State, may again require Defendant to correct any deficiencies, in accordance with the preceding Paragraphs, subject to Defendant's right to invoke Dispute Resolution under Section XI and the right of EPA or the State to seek stipulated

penalties as provided in the preceding Paragraph.

22. Permits. Where any compliance obligation under this Consent Decree requires Defendant to obtain a federal, state, or local permit or approval, Defendant shall submit timely and complete applications and take all other actions necessary to obtain all such permits or approvals. Defendant may seek relief under the provisions of Section X of this Consent Decree (Force Majeure) for any delay in the performance of any such obligation resulting from a failure to obtain, or a delay in obtaining, any permit or approval required to fulfill such obligation, if Defendant has submitted timely and complete applications and have taken all other actions necessary to obtain all such permits or approvals.

23. Defendant shall make copies of the Consent Decree available to all officers, employees, and agents whose duties might reasonably include compliance with any provision of this Consent Decree. Defendant shall also provide copies of this Consent Decree to contractors with responsibilities under this Consent Decree. Defendant shall condition any contract for the performance of work required under this Consent Decree upon performance of the work in conformity with the terms of the Decree.

VII. INJUNCTIVE RELIEF

EMS Audit

24. Defendant developed and EPA, after consultation with the State, approved an EMS Manual for implementing Defendant's EMS.

25. Defendant has retained and EPA, after consultation with the State, has approved an EMS Auditor to complete an Environmental Management System Audit and develop an Environmental Management System Audit Report ("EMS Audit Report") for Defendant's Power

Generation business segment. Defendant shall bear all costs associated with the EMS Auditor duties under this Consent Decree, cooperate fully with the EMS Auditor, and provide the EMS Auditor with access to all records, employees, contractors, and Facilities that the EMS Auditor deems reasonably necessary to effectively perform the duties described in in this Consent Decree.

26. <u>Selection of Replacement EMS Auditor</u>. If at any time Defendant seeks to replace the EMS Auditor, then Defendant shall submit to EPA and the State a list of two or more proposed environmental consultants to serve as EMS Auditor, along with: the name, affiliation, and address of the proposed consultants; information demonstrating how each proposed consultant satisfies EMS auditor qualification requirements of Table 1 in ISO 19011 (First Edition, 2002-10-01); information demonstrating how each proposed consultant has experience in developing and implementing an EMS; information demonstrating that the team proposed to conduct the EMS Audit, in composite, has a working process knowledge of the Defendant's operations or similar operations, and has a working knowledge of federal and state environmental requirements which apply to the Facilities; and descriptions of any previous work contracts, or financial relationship with Defendant.

a. EPA, in consultation with the State, shall notify Defendant of whether it approves any consultant(s) on the list submitted by Defendant. If EPA, after consultation with the State, does not approve any of the proposed consultants on Defendant's list, then Defendant shall submit another list of proposed consultants to EPA and the State within 30 Days of receipt of EPA's written notice of disapproval. If after Defendant has submitted a third list of consultants, which must be submitted within 30 Days of receipt of written notice that EPA has not approved any of the consultants on Defendant's second list, the Parties are unable to agree on an EMS

Auditor, the Parties agree to resolve the selection of the EMS Auditor through the Dispute Resolution process in Section XI of this Consent Decree.

b. Within 10 Days after receipt of EPA's approval, Defendant shall select one consultant from those approved by EPA and shall enter into a contract with the consultant to perform all duties described in Paragraphs 25 and 27. In the event the consultant(s) approved by EPA are no longer available or willing to accept the work described herein when notified of its selection by Defendant, then Defendant shall, within 30 Days after receipt of EPA's approval pursuant to Paragraph 26(a), select another consultant approved by EPA and enter into the contract to perform all duties described herein. Defendant shall ensure that the EMS Auditor performs the duties described herein, and that Defendant's contract with the EMS Auditor shall require the EMS Auditor to perform such duties.

27. EMS Audit and EMS Audit Report. Defendant shall ensure that the EMS Auditor:

a. Conducts and completes an EMS Audit for Defendant's Power Generation business segment no sooner than 180 Days and no later than 545 Days after the Date of Lodging of this CD. The EMS Audit shall be conducted in accordance with ISO 19011 (First Edition, 20002-10-01), using as the EMS metric EPA's "*Compliance-Focused Environmental Management System-Enforcement Agreement Guidance*" ("EPA EMS Guidance"), Appendix A to this Consent Decree, as well as the EMS Manual, and shall determine the following:

(i) Whether there is a defined system, subsystem, program, or planned task for each respective element of the EPA EMS Guidance;

(ii) To what extent the system, subsystem, program, or task has been implemented, and is being maintained;

(iii) The adequacy of each Facility's internal self-assessment procedures for programs and tasks;

(iv) Whether Defendant is effectively communicating environmental requirements to affected parts of the organization, or those working on behalf of the organization;

(v) Whether Defendant is ensuring that contractors and consultants are fully trained to comply with and are complying with any environmental obligations associated with their work for Defendant;

(vi) Whether further improvements should be made to Defendant's written requirements or procedures to better achieve compliance with all environmental laws; and

(vii) Whether there are deviations from Defendant's written requirements or procedures in practice.

b. Within 90 Days of completion of the EMS Audit, prepares an EMS Audit Report describing the results of the EMS Audit, including recommendations necessary for Dominion to improve its environmental management policy and processes and ensure it is consistent with EPA's EMS Guidance.

(i) The EMS Audit Report shall contain: (i) a summary of the audit process, including any obstacles encountered; (ii) detailed findings, including the basis for each finding and each area of concern identified; (iii) identification of any areas of concern addressed during the audit; (iv) recommendations for resolving any area of concern or steps necessary to ensure that Defendant's environmental policies and practices achieve the requirements of the EPA EMS Guidance and EMS Manual; and (v) certification that the EMS Audit was conducted in accordance with the provisions of this Consent Decree.

(ii) The EMS Audit Report shall be provided to EPA and the State upon completion. This report shall be provided to EPA and the State directly from the EMS Auditor. Defendant shall have 30 Days from the date the EMS Audit Report is provided to EPA and the State to provide comments on the report to EPA and the State. EPA, following consultation with the State, shall have the opportunity to review and comment on the EMS Audit Report within sixty (60) days of receipt from the EMS Auditor.

28. EMS Audit Report Implementation. Within 270 Days of its receipt, Defendant shall complete full implementation of the recommendations of the EMS Audit Report and provide a certification in the form identified in the Notice provision of this CD to EPA and the State confirming completion of the EMS Audit Report implementation. An extension of time to complete implementation may only be granted in writing by EPA, after consultation with the State, upon written request by Defendant.

Third-Party Environmental Audit

29. Defendant has retained and EPA, after consultation with the State, has approved an environmental consultant to be the EA Consultant.

30. Selection of Replacement EA Consultant. If at any time Defendant seeks to replace the EA Consultant, then Defendant shall submit to EPA and the State a list of two or more proposed consultants to serve as EA Consultant, along with: the name, affiliation, and address of the proposed consultants; information demonstrating how each proposed consultant has qualifications to perform environmental audits; information demonstrating how each proposed consultant has experience in performing an environmental audit; information

demonstrating that the team proposed to conduct the environmental audit, in composite, has a working process knowledge of the Defendant's operations or similar operations, and has a working knowledge of federal and state environmental requirements which apply to Defendant; and descriptions of any previous work contracts, or financial relationship with Defendant.

a. EPA, in consultation with the State, shall notify Defendant of whether it approves any consultant(s) on the list. If EPA, after consultation with the State, does not approve any of the proposed consultants on Defendant's list, then Defendant shall submit another list of proposed consultants to EPA and the State within 30 Days of receipt of EPA's written notice. If after Defendant has submitted a third list of consultants, which must be submitted within 30 Days of receipt of written notice that EPA has not approved any of the consultants on Defendant's second list, the Parties are unable to agree on an EA Consultant, the Parties agree to resolve the selection of the EA Consultant through the Dispute Resolution process in Section XI of this Consent Decree.

b. Within 10 Days after receipt of EPA's approval, Defendant shall select one consultant from those approved by EPA and shall enter into a contract with the consultant to perform all duties described in this Consent Decree. In the event that the consultant(s) approved by EPA is no longer available or willing to accept the work described herein when notified of their selection by Defendant, then Defendant shall, within 30 Days after receipt of EPA's approval pursuant to Paragraph 30(a), select another consultant approved by EPA and enter into the contract to perform all duties described in herein. Defendant shall ensure that the EA Consultant performs the duties described in this CD and that Defendant's contract with the EA Consultant shall require the EA Consultant to perform such duties

31. The EA Consultant shall conduct a Third-Party Environmental Audit ("EA or "Environmental Audit") of the Chesapeake Energy Center, Chesterfield, Clover, Bremo, Possum Point, Virginia City Hybrid Energy Center, and Yorktown Fixed Facilities as well as three (3) randomly chosen stormwater NPDES permitted construction locations owned and operated by Defendant ("Environmental Audit Facilities"). The Environmental Audit shall be completed within 270 Days of the Effective Date and shall be completed in accordance with acceptable environmental audit industry standards. The Environmental Audit shall evaluate compliance with all applicable NPDES permits at the Environmental Audit Facilities and, at a minimum, with the Applicable Laws.

32. An EA Report shall be prepared by the EA Consultant detailing the results of the Environmental Audit, including, at a minimum: (1) the environmental audit process and protocols followed; (2) the sites and locations audited; (3) the files reviewed; (4) any data or samples obtained; (5) individuals interviewed; (6) all areas of non-compliance and concern; (7) recommendations; and (8) a plan and schedule to correct any non-compliance or area of concern identified. The EA Report shall be provided to EPA and the State no later than 60 Days after completion of the Environmental Audit. EPA, following consultation with the State, shall have an opportunity to review and comment on the EA Report within 60 Days of receipt from the EA Consultant.

33. Responses and actions to fully address and correct any non-compliance or areas of concern identified by the EA Report shall be completed as expeditiously as possible and shall not take longer than 270 Days to complete after the submission of the EA Report, unless an extension of time is requested in writing by Defendant and granted by EPA in writing, after

consultation with the State.

Internal Environmental Audits

34. Defendant shall continue to implement its Internal Environmental Audit Program ("IEAP") and include an IEAP Report in the Semi-Annual report required by Section VIII of this Consent Decree.

35. Each IEAP Report shall include: (1) the identification of any Facility audited within the most recent semi-annual period; (2) a summary of information reviewed to assess compliance with Applicable Law; (3) a statement as to whether there are, and a description of, any instances of non-compliance with Applicable Law; and if so, (4) description of and confirmation that corrective and/or preventive actions have been taken or are being implemented to address any instances of non-compliance with Applicable Law.

State SWCL Injunctive Relief: Seep Identification and Mitigation

36. Within 180 Days of lodging of this CD, in addition to inspections required by the EPA CCR Rule, 40 CFR Part 257, Subpart D, Virginia Solid Waste Management Regulations, 9 VAC 20-81, Virginia Impounding Structure Regulations, 4 VAC 50-20, and applicable permits, Defendant shall continue to conduct at least monthly site walk-downs required by applicable law or in accordance with best management practices, which must include at a minimum a visual inspection of adjacent shorelines at low-tide at its Coal Ash Impoundment Facilities ("CAIF"). Any seeps or surface expressions of groundwater observed to be discharging to surface waters at a CAIF shall be reported within 24 hours to the State in addition to any other legally required notifications. Defendant shall then, in coordination and consultation with and as approved by the State, take action to determine whether further monitoring, characterization, or mitigation is

warranted. If determined to be warranted, Defendant shall develop an appropriate corrective action plan for State review and approval. After approval, Defendant shall implement the plan in accordance with its terms.

State SWCL Seep Specific Injunctive Relief

37. Defendant shall continue to implement the Seep Mitigation Plan ("SMP") submitted to the State to address the Eastern Shoreline Seeps at the Chesterfield Power Station. In implementing this plan, Defendant shall:

a. Submit quarterly status reports to the State following implementation of the mitigation strategy describing the results of follow-up monitoring;
b. Submit an annual review report to the State with each 4th quarter status report for three years that quantifies the success of the chosen mitigation method as well as effectiveness;
c. Submit an evaluation to the State to occur no later than three years after installation of a remedy described in the SMP to include data analysis and trend analysis to evaluate the long-term effectiveness of the remedy; and
d. Submit to the State a revised SMP within 90 days following a DEQ notification that the selected mitigation plan is not achieving the desired goal.

EPCRA Release Training

38. EPCRA Release Training. For the EPCRA Facility, within 120 Days of the Effective Date, Defendant shall conduct training on its Release SOPs for notifying the appropriate federal, state, and local emergency responders of a release of any hazardous substance or EHS exceeding the reportable quantity ("RQ") as required by the emergency release notification requirements of Section 103 of CERCLA, 42 U.S.C. § 9603, and Section 304 of EPCRA, 42 U.S.C. § 11004, and their implementing regulations at 40 C.F.R. Parts 302 and 355.

39. Within 60 days of completing the training in accordance with Paragraph 38, Defendant shall develop and submit to EPA an Emergency Release Process Report ("the Release

SOPs Report"). The Release SOPs Report shall include a certification of completion of training, including a report on the dates of training and personnel trained.

40. Between 365 Days and 425 Days after the submission of the Release SOPs Report, Defendant shall certify to EPA in writing that the Release SOPs are current, accurate and being implemented.

Annual Training

41. Defendant shall provide and require annual training for all individuals with environmental management responsibilities at any Facility, including, but not limited to: (a) Clean Water Act compliance; (b) applicable requirements in the EMS Manual; and (c) applicable obligations in this Consent Decree.

VIII. REPORTING REQUIREMENTS

Semi-Annual Reports

42. During the term of this Consent Decree, Defendant shall submit semi-annual reports to EPA and the State concerning compliance with the terms of this CD and Applicable Law. The semi-annual reports may be submitted in electronic format and shall be due at the end of the month following the end of each semi-annual period (i.e. by July 31 and January 31), starting with the first full semi-annual period after the Effective Date. The semi-annual reports shall contain, at a minimum, the following:

a. Information regarding any violation of Applicable Law at any Facility that occurred within the reporting period, including: (i) a summary of Effluent Limit Violations, including total number of Effluent Limit Violations; (ii) NOVs; (iii) unauthorized discharges; (iv) a summary of steps taken or planned steps to remedy the violations identified in (i) through (iii); and (v) if applicable, proof of payment of civil or stipulated penalty under this Consent Decree or any state consent decree or consent order;

b. Certification of and any applicable rosters of training required under this Consent Decree;

c. Following completion of the EMS Audit required by this Consent Decree, a certification of material conformance with the elements of the EMS Manual, or, for any material nonconformance, an explanation of the cause of the nonconformance and remedial steps taken or to be taken;

d. The status of Consent Decree implementation, including the status of any problems encountered or anticipated, together with implemented or proposed solutions;

e. A description of any noncompliance with the requirements of this Consent Decree and an explanation of the noncompliance's likely cause and the remedial steps taken, or to be taken, to prevent or minimize such noncompliance;

f. The IEAP Report, required by Paragraph 35; and

g. A description of each Consent Decree violation for which Defendant has submitted to EPA an unresolved Force Majeure claim or intends to submit a Force Majeure claim pursuant to Section X of this Consent Decree.

Other Reporting Requirements

43. If Defendant violates, or has reason to believe that it may violate, any requirement of this Consent Decree, Defendant shall notify the United States and the State of such violation and its likely duration, in writing, within 7 Days of the day Defendant first becomes aware of the violation, and include an explanation of the violation's likely cause and of the remedial steps

taken, or to be taken, to prevent or minimize such violation. If the cause of a violation cannot be fully explained at the time the notification is due, Defendant shall so state in the notification. Defendant thereafter shall investigate the cause of the violation and submit an amendment to the report, including a full explanation of the cause of the violation, within 30 Days of the day Defendant becomes aware of the violation. Nothing in this Paragraph or the following Paragraph relieves Defendant of its obligation to provide the notice required by Section X of this Consent Decree (Force Majeure).

44. Whenever any violation of this Consent Decree or of any Applicable Law or other event affecting Defendant's performance under this Consent Decree may pose an immediate threat to the public health or welfare or the environment, Defendant shall notify EPA and the State orally or by electronic or facsimile transmission as soon as possible, but no later than 24 hours after Defendant first knew of the violation or event. This procedure is in addition to the requirements set forth in the preceding Paragraph.

45. All reports shall be submitted to the persons designated in Section XV of this Consent Decree (Notices).

46. Each report submitted by Defendant under this Section shall be signed by an official of the submitting party and include the following certification:

> I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

This certification requirement does not apply to emergency or similar notifications where compliance would be impractical.

47. The reporting requirements of this Consent Decree do not relieve Defendant of any reporting obligation required by Applicable Law, or by any other federal, state, or local law, regulation, permit, or other requirement.

48. Any information provided pursuant to this Consent Decree may be used by the United States or the State in any proceeding to enforce the provisions of this Consent Decree and as otherwise permitted by law.

IX. STIPULATED PENALTIES

49. Defendant shall be liable for stipulated penalties to the United States and the State for violations as specified below, unless excused under Section X (Force Majeure). A violation includes failing to perform any obligation required by the terms of this Consent Decree, including any work plan or schedule approved under this Consent Decree, according to all applicable requirements of this Consent Decree and within the specified time schedules established by or approved under this Consent Decree.

50. Stipulated penalties under this Section shall begin to accrue on the Day after performance is due or on the Day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. If performance is satisfactorily completed, or if a violation ceases on a Saturday, Sunday, or federal holiday, the date of completion of performance and the date that the violation ceases shall be the date of actual completion or cessation, rather than the following business day. Stipulated penalties shall accrue simultaneously for separate violations of this Consent Decree.

51. Any Plaintiff, in the unreviewable exercise of its discretion may reduce or waive stipulated penalties otherwise due to that Plaintiff under this Consent Decree.

52. Stipulated penalties shall continue to accrue as provided in Paragraph 50 during any Dispute Resolution under Section XI, but need not be paid until the following:

a. If the dispute is resolved by agreement or by a decision of EPA or the State that is not appealed to the Court, Defendant shall pay accrued penalties determined to be owed, together with interest, to the United States and the State within 30 Days of the effective date of the agreement or the receipt of EPA's or the State's decision or order.

b. If the dispute is appealed to the Court and the United States or the State prevail in whole or in part, Defendant shall pay all accrued penalties determined by the Court to be owing, together with interest, to the United States and the State within 60 Days of receiving the Court's decision or order, except as provided in subparagraph (c), below.

c. If any Party appeals the Court's decision, Defendant shall pay all accrued penalties determined to be owed, together with interest, within 15 Days of receiving the final appellate court decision.

53. If Defendant fails to pay stipulated penalties according to the terms of this Consent Decree, Defendant shall be liable for interest on such penalties, as provided for in 28 U.S.C. § 1961, accruing as of the date payment became due. Nothing in this Paragraph shall be construed to limit the United States or the State from seeking any remedy otherwise provided by law for Defendant's failure to pay any stipulated penalties.

54. Subject to the provisions of Section XIII of this Consent Decree (Effect of Settlement/Reservation of Rights), the stipulated penalties provided for in this Consent Decree

shall be in addition to any other rights, remedies, or sanctions available to the United States or the State for Defendant's violation of this Consent Decree or applicable law. Where a violation of this Consent Decree is also a violation of relevant statutory or regulatory requirements, Defendant shall be allowed a credit, for any stipulated penalties paid, against any statutory penalties imposed for such violation.

55. Non-Compliance with Consent Decree. The following stipulated penalties shall accrue per violation per Day for each violation of any requirement of Paragraph 7 (transfer of Facilities); Section V (Civil Penalty); Section VI (Compliance Requirements); Section VII (Injunctive Relief); and Section XII (Information Collection and Retention) of this Consent Decree:

Penalty Per Violation Per Day	Period of Noncompliance
$750 per Day or portion thereof	1st through 14th Day
$1,250 per Day or portion thereof	15th through 30th Day
$2,500 per Day or portion thereof	31st Day and beyond

56. Non-Compliance with Reporting Requirements. The following stipulated penalties shall accrue per violation per Day for each violation of the Reporting Requirements under Section VIII of this Consent Decree:

Penalty Per Violation Per Day	Period of Noncompliance
$250 per Day or portion thereof	1st through 14th Day
$500 per Day or portion thereof	15th through 30th Day
$1,000 per Day or portion thereof	31st Day and beyond

57. Non-Compliance with NPDES Permit Limits. The following stipulated penalties shall accrue for each Effluent Limit Violation that occurs at any Facility after the Effective Date of this Consent Decree, except for any Daily Violation that is in compliance with an alternative limit identified in a State compliance order:

Per Violation	Period of Noncompliance
$1,000	Daily Violation
$3,000	Monthly Violation

58. Defendant shall pay any stipulated penalty pursuant to this Consent Decree to the United States and the State within 30 Days of receiving a written demand by any Plaintiff. The Plaintiff making a demand for payment of a stipulated penalty shall simultaneously send a copy of the demand to the other Plaintiff. For tracking purposes, the United States, EPA, or the State, will send notice of any demand letter to: (i) EPA via email at CINWD_AcctsReceivable@epa.gov and via regular mail at U.S. EPA Cincinnati Finance Office, MS: WG-32B26 Martin Luther King Drive, Cincinnati, Ohio 45268; (ii) EPA via email to the U.S. EPA Regional Hearing Clerk at R3_Hearing_Clerk@epa.gov.

59. Defendant shall pay 50 percent of any stipulated penalty pursuant to Paragraphs 55 and 56 to the United States and 50 percent to the State, except that for stipulated penalties from violations that occur in West Virginia, Defendant shall pay the entire amount of the stipulated penalty to the United States and for any stipulated penalties related to violations of Paragraphs 36 or 37 Defendant shall pay the entire amount to the State.

60. Defendant shall pay stipulated penalties owing to the United States pursuant to this CD in the manner set forth in Paragraph 12 and with the confirmation notices and transmittal letter information required by Paragraph 12, except that the transmittal letter shall state that the payment is for stipulated penalties and shall state for which violation(s) the penalties are being paid. Defendant shall pay stipulated penalties owing to the State pursuant to this Consent Decree in the manner set forth in Paragraph 13, except that the confirmation notice shall state that the payment is for stipulated penalties and shall state for which violation(s) the penalties are being

paid.

X. FORCE MAJEURE

61. "Force Majeure," for purposes of this Consent Decree, is defined as any event arising from causes beyond the control of Defendant, of any entity controlled by Defendant, or of Defendant's contractors, that delays or prevents the performance of any obligation under this Consent Decree despite Defendant's best efforts to fulfill the obligation. The requirement that Defendant exercise "best efforts to fulfill the obligation" includes using best efforts to anticipate any potential Force Majeure event and best efforts to address the effects of any such event (a) as it is occurring and (b) after it has occurred to prevent or minimize any resulting delay to the greatest extent possible. "Force Majeure" does not include Defendant's financial inability to perform any obligation under this Consent Decree.

62. If any event occurs or has occurred that may delay the performance of any obligation under this Consent Decree, whether or not caused by a Force Majeure event, Defendant shall provide notice orally or by electronic or facsimile transmission to EPA and the State within 72 hours of when Defendant first knew that the event might cause a delay. Within 7 Days thereafter, Defendant shall provide in writing to EPA and the State an explanation and description of the reasons for the delay; the anticipated duration of the delay; all actions taken or to be taken to prevent or minimize the delay; a schedule for implementation of any measures to be taken to prevent or mitigate the delay or the effect of the delay; Defendant's rationale for attributing such delay to a Force Majeure event if it intends to assert such a claim; and a statement as to whether, in the opinion of Defendant, such event may cause or contribute to an endangerment to public health, welfare or the environment. Defendant shall include with any

notice all available documentation supporting the claim that the delay was attributable to a Force Majeure. Failure to comply with the above requirements shall preclude Defendant from asserting any claim of Force Majeure for that event for the period of time of such failure to comply, and for any additional delay caused by such failure. Defendant shall be deemed to know of any circumstance of which Defendant, any entity controlled by Defendant, or Defendant's contractors knew or should have known.

63. If EPA, after a reasonable opportunity for review and comment by the State, agrees that the delay or anticipated delay is attributable to a Force Majeure event, the time for performance of the obligations under this Consent Decree that are affected by the Force Majeure event will be extended by EPA, after a reasonable opportunity for review and comment by the State, for such time as is necessary to complete those obligations. An extension of the time for performance of the obligations affected by the Force Majeure event shall not, of itself, extend the time for performance of any other obligation. EPA will notify Defendant in writing of the length of the extension, if any, for performance of the obligations affected by the Force Majeure event.

64. If EPA, after a reasonable opportunity for review and comment by the State, does not agree that the delay or anticipated delay has been or will be caused by a Force Majeure event, EPA will notify Defendant in writing of its decision.

65. If Defendant elects to invoke the dispute resolution procedures set forth in Section XI (Dispute Resolution) in response to EPA's determination in Paragraph 64, it shall do so no later than 20 Days after receipt of EPA's notice. In any such proceeding, Defendant shall have the burden of demonstrating by a preponderance of the evidence that the delay or anticipated delay has been or will be caused by a Force Majeure event, that the duration of the delay or the

extension sought was or will be warranted under the circumstances, that best efforts were exercised to avoid and mitigate the effects of the delay, and that Defendant complied with the requirements of Paragraphs 61 and 62, above. If Defendant carries this burden, the delay at issue shall be deemed not to be a violation of the affected obligation of this Consent Decree identified to EPA and the Court.

XI. DISPUTE RESOLUTION

66. Unless otherwise expressly provided for in this Consent Decree, the Dispute Resolution procedures of this Section shall be the exclusive mechanism to resolve disputes arising under or with respect to this Consent Decree. Defendant's failure to seek resolution of a dispute under this Section shall preclude Defendant from raising any such issue as a defense to an action by the United States, EPA or the State to enforce any obligation of Defendant arising under this Consent Decree.

67. Informal Dispute Resolution. Any dispute subject to Dispute Resolution under this Consent Decree shall first be the subject of informal negotiations. The dispute shall be considered to have arisen when Defendant sends the United States, EPA and the State a written Notice of Dispute. The Notice of Dispute shall state clearly the matter in dispute. The period of informal negotiations shall not exceed beyond 30 Days from the date the dispute arises, unless that period is modified by written agreement. If the Parties cannot resolve a dispute by informal negotiations, then the position advanced by the United States, after consultation with the State, shall be considered binding unless, within 15 Days after the conclusion of the informal negotiation period, Defendant invokes formal dispute resolution procedures as set forth below.

68. Formal Dispute Resolution. Defendant shall invoke formal dispute resolution

procedures, within the time period provided in the preceding Paragraph, by serving on the United States, EPA and the State a written Statement of Position regarding the matter in dispute. The Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting Defendant's position and any supporting documentation relied upon by Defendant.

69. The United States shall serve its Statement of Position within 45 Days of receipt of Defendant's Statement of Position. The United States' Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting that position and any supporting documentation relied upon by the United States, and shall be developed in consultation with State. The United States' Statement of Position shall be binding on Defendant, unless Defendant files a motion for judicial review of the dispute in accordance with Paragraph 71.

70. An administrative record of the dispute shall be maintained by EPA and shall contain all Statements of Position, including supporting documentation, submitted pursuant to this Section.

71. Defendant may seek judicial review of the dispute by filing with the Court and serving on the United States and the State, in accordance with Section XV of this Consent Decree (Notices), a motion requesting judicial resolution of the dispute. The motion must be filed within 20 Days of receipt of the United States' Statement of Position pursuant to Paragraph 69. The motion shall contain a written statement of Defendant's position on the matter in dispute, including any supporting factual data, analysis, opinion, or documentation, and shall set forth the relief requested and any schedule within which the dispute must be resolved for orderly

implementation of this Consent Decree.

72. The United States and/or the State shall respond to Defendant's motion within the time period allowed by the Local Rules of this Court. Defendant may file a reply memorandum, to the extent permitted by the Local Rules.

73. Standard of Review

a. Disputes Concerning Matters Accorded Record Review. Except as otherwise provided in this Consent Decree, in any dispute brought under Paragraph 68 pertaining to the adequacy or appropriateness of plans, procedures to implement plans, schedules or any other items requiring approval by EPA under this Consent Decree; the adequacy of the performance of work undertaken pursuant to this Consent Decree; and all other disputes that are accorded review on the administrative record under applicable principles of administrative law, Defendant shall have the burden of demonstrating, based on the administrative record, that the position of the United States is arbitrary and capricious or otherwise not in accordance with law.

b. Other Disputes. Except as otherwise provided in this Consent Decree, in any other dispute brought under Paragraph 68, Defendant shall bear the burden of demonstrating that its position fulfills the terms, conditions, requirements, and objectives of this Consent Decree.

74. The invocation of Dispute Resolution procedures under this Section shall not, by itself, extend, postpone, or affect in any way any obligation of Defendant under this Consent Decree, unless and until final resolution of the dispute so provides. Stipulated penalties with respect to the disputed matter shall continue to accrue from the first Day of noncompliance, but payment shall be stayed pending resolution of the dispute as provided in Paragraph 52. If

Defendant does not prevail on the disputed issue, stipulated penalties shall be assessed and paid as provided in Section IX (Stipulated Penalties).

XII. INFORMATION COLLECTION AND RETENTION

75. The United States, the State, and their designated representatives, including attorneys, contractors, and consultants, shall have the right of entry onto any Facility under the ownership or control of the Defendant, at all reasonable times, upon presentation of credentials, to:

a. monitor the progress of activities required under this Consent Decree;

b. verify any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtain samples and, upon request, splits of any samples taken by Defendant or its representatives, contractors, or consultants relating to Defendant's compliance with this Consent Decree;

d. obtain documentary evidence, including photographs and similar data, relating to Defendant's compliance with this Consent Decree; and

e. assess Defendant's compliance with this Consent Decree.

76. Upon request, Defendant shall provide EPA and the State, or their authorized representatives, splits of any samples taken by Defendant relating to the Facilities' compliance with this Consent Decree. Upon request, EPA and the State shall provide Defendant splits of any samples relating to the Facilities' compliance with this Consent Decree taken by EPA or the State.

77. Until three (3) years after the termination of this Consent Decree, Defendant shall

retain, and shall instruct its contractors and agents to preserve, all non-identical copies of all documents, records, or other information (including documents, records, or other information in electronic form) in Defendant's or its contractors' or agents' possession or control, or that come into its or its contractors' or agents' possession or control, and that relate in any manner to Defendant's performance of its obligations under this Consent Decree. The foregoing may be maintained electronically. This information-retention requirement shall apply regardless of any contrary corporate or institutional policies or procedures. At any time during this information-retention period, upon request by the United States or the State, Defendant shall provide copies of any non-privileged documents, records, or other information required to be maintained under this Paragraph.

78. At the conclusion of the information-retention period provided in the preceding Paragraph, Defendant shall notify the United States and the State at least 60 Days prior to the destruction of any documents, records, or other information subject to the requirements of the preceding Paragraph and, upon request by the United States or the State, Defendant shall deliver copies of any such non-privileged documents, records, or other information to EPA or the State. After the expiration of the 60-Day period identified in this Paragraph, Defendant's obligations with respect to document retention under this Consent Decree shall terminate and Defendant shall be entitled to reinstate the application of its standard document retention policies.

79. Defendant may assert that information required to be provided to the United States or the State under Paragraphs 77 and 78 of this Consent Decree is privileged under the attorney-client privilege or any other privilege recognized by federal law. If Defendant asserts such a privilege, it shall provide the following: (a) the title of the document, record, or

information; (b) the date of the document, record, or information; (c) the name and title of each author of the document, record, or information; (d) the name and title of each addressee and recipient; (e) a description of the subject of the document, record, or information; and (f) the privilege asserted by Defendant. However, no documents, records, or other information required to be created or generated pursuant to the requirements of this Consent Decree shall be withheld on grounds of privilege.

80. Defendant may assert that information provided to the United States or the State under this Consent Decree is protected as Confidential Business Information ("CBI") by following the procedures set forth in 40 C.F.R. Part 2 and comparable state law. The United States and the State will treat such materials in accordance with the applicable federal or state CBI regulations.

81. This Consent Decree in no way limits or affects any right of entry and inspection, or any right to obtain information, held by the United States or the State pursuant to applicable federal or state laws, regulations, or permits, nor does it limit or affect any duty or obligation of Defendant to maintain documents, records, or other information imposed by applicable federal or state laws, regulations, or permits.

XIII. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS

82. This Consent Decree resolves the civil claims of the United States and the State for the violations alleged in the Complaint filed in this action.

83. The United States and the State reserve all legal and equitable remedies available to enforce the provisions of this Consent Decree, except as expressly stated in Paragraph 82. This Consent Decree shall not be construed to limit the rights of the United States or the State to

obtain penalties or injunctive relief under the CWA or implementing regulations, or under other federal or state laws, regulations, or permit conditions, except as expressly specified in Paragraph 82.

84. In any subsequent administrative or judicial proceeding initiated by the United States or the State for injunctive relief, civil penalties, or other appropriate relief relating to the violations alleged in the Complaint, Defendant shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, claim-splitting, or other defenses based upon any contention that the claims raised by the United States or the State in the subsequent proceeding were or should have been brought in the instant case, except with respect to claims that have been specifically resolved pursuant to Paragraph 82 of this Section.

85. This Consent Decree is not a permit, or a modification of any permit, under any federal, state, or local laws or regulations. Defendant is responsible for achieving and maintaining complete compliance with all applicable federal, state, and local laws, regulations, and permits; and Defendant's compliance with this Consent Decree shall be no defense to any action commenced pursuant to any such laws, regulations, or permits, except as set forth herein. The United States and the State do not, by their consent to the entry of this Consent Decree, warrant or aver in any manner that Defendant's compliance with any aspect of this Consent Decree shall result in compliance with provisions of the CWA, 33 U.S.C. § 1311, *et seq.*, or with any other provisions of federal, state, or local laws, regulations, or permits. Application for construction grants, State Revolving Loan Funds, or any other grants or loans, or other delays caused by inadequate facility planning or plans and specifications on the part of Defendant shall

not be cause for extension of any required compliance date in this Consent Decree.

86. This Consent Decree does not limit or affect the rights of Defendant or of the United States or the State against any third parties, not party to this Consent Decree, nor does it limit the rights of third parties, not party to this Consent Decree, against Defendant, except as otherwise provided by law.

87. This Consent Decree shall not be construed to create rights in, or grant any cause of action to, any third-party not party to this Consent Decree.

88. By the execution of this Consent Decree, Defendant releases and shall hold harmless the United States and the State, and their instrumentalities, agents, and employees, in their official and personal capacities, of any and all liability or claims arising out of or otherwise related to the negotiations leading to this Consent Decree and all matters contained therein.

XIV. COSTS

89. The Parties shall bear their own costs of this action, including attorneys' fees, except that the United States and the State shall each be entitled to collect the costs (including attorneys' fees) incurred in any action necessary to collect any portion of the civil penalty or any stipulated penalties due hereunder but not paid by Defendant.

XV. NOTICES

90. Unless otherwise specified herein, whenever notifications, submissions, reports, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

To the United States:

By email: eescdcopy.enrd@usdoj.gov
Re: DJ # 90-5-1-1-11859

By mail: EES Case Management Unit
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611
Washington, D.C. 20044-7611
Re: DJ # 90-5-1-1-11859

To EPA:

By email: harsh.chad@epa.gov

By mail: Director, Office of Civil Enforcement
U.S. Environmental Protection Agency
Ariel Rios Building, 2241A
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

and

NPDES Enforcement Branch Chief
U.S. EPA Region III
1650 Arch Street, 3WP42
Philadelphia, PA 19103

To the Commonwealth of Virginia:

By email: Kristen.Sadtler@deq.virginia.gov

By mail: Director, Division of Enforcement
PO Box 1105
Richmond, VA 23218

To Defendant:

By mail: Amanda B. Tornabene
Vice President, Environmental Services
Dominion Energy Services, Inc.
5000 Dominion Boulevard
Glen Allen, VA 23060

Clay T. Burns
Senior Counsel, Law Department
Dominion Energy Services, Inc.
120 Tredegar St.
Richmond, VA 23219

By email: Amanda.b.tornabene@dominionenergy.com
clay.t.burns@dominionenergy.com

91. Any Party may, by written notice to the other Parties, change its designated notice recipient or notice address provided above.

92. Notices submitted pursuant to this Section shall be deemed submitted upon mailing, unless otherwise provided in this Consent Decree or by mutual agreement of the Parties in writing.

XVI. RETENTION OF JURISDICTION

93. The Court shall retain jurisdiction over this case until termination of this Consent Decree, for the purpose of resolving disputes arising under this Consent Decree or entering orders modifying this Consent Decree, pursuant to Sections XI (Dispute Resolution) or XVII (Modification) or effectuating or enforcing compliance with the terms of this Decree.

XVII. MODIFICATION

94. The terms of this Consent Decree, including any attached Appendices, may be modified only by a subsequent written agreement signed by all the Parties. Where the modification constitutes a material change to this Consent Decree, it shall be effective only upon approval by the Court. Deadline extensions of less than 90 Days shall not be considered a material change to the Consent Decree requiring Court approval.

95. Any disputes concerning modification of this Consent Decree shall be resolved

pursuant to Section XI of this Decree (Dispute Resolution); provided, however, that, instead of the burden of proof provided by Paragraph 73, the Party seeking the modification bears the burden of demonstrating that it is entitled to the requested modification in accordance with Federal Rule of Civil Procedure 60(b).

XVIII. TERMINATION

96. After Defendant has completed the requirements of Paragraphs 24-33 (EMS Audit and Environmental Audit) of this Decree and has thereafter maintained satisfactory compliance with Section VI (Compliance Requirements), Section VII (Injunctive Relief), and Section VIII (Reporting Requirements) of this Consent Decree for a period of two years, and has paid the civil penalty and any accrued and demanded stipulated penalties as required by this Consent Decree, Defendant may serve upon the United States and the State a Request for Termination, stating that Defendant has satisfied those requirements, together with all necessary supporting documentation.

97. Following receipt by the United States and the State of Defendant's Request for Termination, the Parties shall confer informally concerning the Request and any disagreement that the Parties may have as to whether Defendant has satisfactorily complied with the requirements for termination of this Consent Decree. If the United States and the State agree that the Consent Decree may be terminated, the Parties shall submit, for the Court's approval, a joint stipulation terminating the Consent Decree.

98. If the United States and the State do not agree that the Consent Decree may be terminated, Defendant may invoke Dispute Resolution under Section XI of this Consent Decree. However, Defendant shall not seek Dispute Resolution of any dispute regarding termination,

under Paragraph 68 of Section XI, until 30 Days after service of its Request for Termination.

XIX. PUBLIC PARTICIPATION

99. This Consent Decree shall be lodged with the Court for a period of not less than 30 Days for public notice and comment in accordance with 28 C.F.R. § 50.7. The United States reserves the right to withdraw or withhold its consent if the comments regarding this Consent Decree disclose facts or considerations indicating that this Consent Decree is inappropriate, improper, or inadequate. Defendant consents to entry of this Consent Decree without further notice and agrees not to withdraw from or oppose entry of this Consent Decree by the Court or to challenge any provision of the Consent Decree, unless the United States has notified Defendant in writing that it no longer supports entry of the Consent Decree.

XX. SIGNATORIES/SERVICE

100. Each undersigned representative of the Defendant, the Assistant Attorney General for the Environment and Natural Resources Division of the Department of Justice, and the undersigned representative of the State certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

101. This Consent Decree may be signed in counterparts, and its validity shall not be challenged on that basis. Defendant agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rules 4 and 5 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXI. INTEGRATION

102. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in the Consent Decree and supersedes all prior agreements and understandings, whether oral or written, concerning the settlement embodied herein. Other than deliverables that are subsequently submitted and approved pursuant to this Consent Decree, no other document, nor any representation, inducement, agreement, understanding, or promise, constitutes any part of this Decree or the settlement it represents, nor shall it be used in construing the terms of this Consent Decree.

XXII. FINAL JUDGMENT

103. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment of the Court as to the United States, the State, and Defendant. The Court finds that there is no just reason for delay and therefore enters this judgment as a final judgment under Fed. R. Civ. P. 54 and 58.

XXIII. APPENDICES

104. The following appendices are attached to and part of this Consent Decree:

Appendix A: EPA EMS Guidance

Appendix B: Fixed Facilities

SO ORDERED THIS _____ DAY OF __________, 2020.

____
United States District Judge
Eastern District of Virginia

THE UNDERSIGNED PARTIES enter into this Consent Decree in the matter of *United States, et al. v. Virginia Electric and Power Company d/b/a Dominion Energy Virginia*

FOR THE UNITED STATES OF AMERICA

Date: 3/6/2020

NATHANIEL DOUGLAS
Deputy Section Chief
Environment Enforcement Section

Date: 3/6/2020

LAURA THOMS
Senior Attorney
Environment Enforcement Section
U.S. Department of Justice
P.O. Box 7611
Washington, D.C. 20044
Telephone: 202-305-0260
Fax: 202-514-0097
laura.thoms@usdoj.gov

THE UNDERSIGNED PARTIES enter into this Consent Decree in the matter of *United States, et al. v. Virginia Electric and Power Company d/b/a Dominion Energy Virginia*

FOR THE UNITED STATES OF AMERICA

G. ZACHARY TERWILLIGER
United States Attorney
Eastern District of Virginia

Date: March 13, 2020

ROBERT P. MCINTOSH
Assistant United States Attorney
Virginia State Bar No. 66113
919 East Main Street, Suite 1900
Richmond, Virginia 23219
Telephone: (804) 819-7404
Fax: (804) 771-2316
Email: Robert.McIntosh@usdoj.gov

THE UNDERSIGNED PARTIES enter into this Consent Decree in the matter of *United States, et al. v. Virginia Electric and Power Company d/b/a Dominion Energy Virginia*

FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Date: 12/18/19

Susan Parker Bodine
Assistant Administrator
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

Date: 12/12/19

Rosemarie Kelly
Director, Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

Date: 11/26/19

Mark Pollins
Director, Water Enforcement Division
Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

Date: 11/25/2019

Graciela Garcia Pendleton
Attorney-Advisor, Water Enforcement Division
Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460

THE UNDERSIGNED PARTIES enter into this Consent Decree in the matter of *United States, et al. v. Virginia Electric and Power Company d/b/a Dominion Energy Virginia*

FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Date: 12·02·2019

COSMO SERVIDIO
Regional Administrator
U.S. Environmental Protection Agency, Region III
1650 Arch Street
Philadelphia, PA 19103-2029

Date: 11/18/2019

CECIL RODRIGUES
Regional Counsel
U.S. Environmental Protection Agency, Region III
1650 Arch Street
Philadelphia, PA 19103-2029

Date: 11/7/19

DOUGLAS FRANKENTHALER
Assistant Regional Counsel
U.S. Environmental Protection Agency, Region III
1650 Arch Street
Philadelphia, PA 19103-2029

THE UNDERSIGNED PARTIES enter into this Consent Decree in the matter of *United States, et al. v. Virginia Electric and Power Company d/b/a Dominion Energy Virginia*

FOR THE COMMONWEALTH OF VIRGINIA

Date: 2·21·20

David Grandis

Mark R. Herring
Attorney General of Virginia

Donald D. Anderson
Deputy Attorney General

Paul Kugelman, Jr.
Senior Assistant Attorney General, Chief

David C. Grandis
Senior Assistant Attorney General

Office of the Attorney General
202 North 9th Street
Richmond, VA 23219
(804) 225-2741 – telephone
(804) 786-2650 – facsimile

THE UNDERSIGNED PARTIES enter into this Consent Decree in the matter of *United States, et al. v. Virginia Electric and Power Company d/b/a Dominion Energy Virginia*

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FOR DEFENDANT

Date: November 8, 2019

Paul D. Koonce
Paul D. Koonce
President and Chief Operating Officer – Power Generation Group
Virginia Electric and Power Company

APPENDIX A

COMPLIANCE-FOCUSED
ENVIRONMENTAL MANAGEMENT SYSTEM ELEMENTS

1. Environmental Policy

    a. This policy, upon which the EMS is based, must clearly communicate management commitment to achieving compliance with applicable federal, state, and local environmental statutes, regulations, enforceable agreements, and permits (hereafter, "environmental requirements"), minimizing risks to the environment from unplanned or unauthorized releases of hazardous or harmful contaminants, and continual improvement in environmental performance. The policy should also state management's intent to provide adequate personnel and other resources for the EMS.

2. Organization, Personnel, and Oversight of EMS

    a. Identifies and defines specific duties, roles, responsibilities, and authorities of key environmental staff in implementing and sustaining the EMS (e.g., could include position descriptions and/or performance standards for all environmental department personnel, and excerpts from others having specific environmental duties, and regulatory compliance responsibilities).

    b. Includes organization charts that identify units, line management, and other individuals having environmental duties and regulatory compliance responsibilities.

    c. Includes ongoing means of communicating environmental issues and information among the various levels and functions of the organization, to include all persons working for or on behalf of the organization (e.g., on-site service providers and contractors who function as de facto employees), and for receiving and addressing their concerns.

3. Accountability and Responsibility

    a. Specifies accountability and environmental responsibilities of organization's managers, and managers of other organizations acting on its behalf for environmental protection and risk reduction measures, assuring compliance, required reporting to regulatory agencies, and corrective actions implemented in their area(s) of responsibility.

b. Describes incentive programs for managers and employees to perform in accordance with compliance policies, standards, and procedures.

c. Describes potential consequences for departure from specified operating procedures, including liability for civil/administrative penalties imposed as a result of noncompliance.

4. Environmental Requirements

a. Describes process for identifying potentially applicable environmental requirements; interpreting their applicability to specific operations, emissions, and waste streams; and effectively communicating those applicable environmental requirements to affected persons working for or on behalf of the organization.

b. Describes a process for developing, implementing and maintaining ongoing internal compliance monitoring to ensure that facility activities conform to applicable environmental requirements. Compliance monitoring shall include inspections and measurements, as appropriate.

c. Describes procedures for prospectively identifying and obtaining information about changes and proposed changes in environmental requirements, and incorporating those changes into the EMS (i.e., regulatory "change management").

d. Describes a procedure for communicating with regulatory agencies regarding environmental requirements and regulatory compliance.

5. Assessment, Prevention, and Control

a. Identifies an ongoing process for assessing operations, for the purposes of preventing, controlling, or minimizing reasonably foreseeable releases, environmental process hazards, and risks of noncompliance with environmental requirements. This process shall include identifying operations and waste streams where equipment malfunctions and deterioration, and/or operator errors or deliberate malfeasance, are causing, or have the potential to cause: (1) unplanned or unauthorized releases of hazardous or harmful contaminants to the environment, (2) a threat to human health or the environment, or (3) noncompliance with environmental requirements.

b. Describes process for identifying operations and activities where documented operating criteria, such as standard operating procedures (SOPs), are needed to prevent noncompliance or unplanned/unauthorized releases of hazardous or harmful contaminants, and defines a uniform process for developing, approving and implementing the documented operating criteria.

c. Describes a system for conducting and documenting routine, objective, self-inspections by department supervisors and trained staff, especiallyat locations identified by the process described in (a) above, to check for malfunctions, deterioration, worker adherence to operating criteria, unusual situations, and unauthorized or unplanned releases.

d. Describes a "management of change" process to ensure identification and consideration of environmental requirements, the environmental aspects/impacts, and potential operator errors or deliberate malfeasance during planning, design, and operation of ongoing, new, and/or changing buildings, processes, equipment, maintenance activities, and products.

6. Environmental Incident and Non-compliance Investigations

a. Describes standard procedures and requirements for internal and external reporting of environmental incidents and noncompliance with environmental requirements.

b. Establishes procedures for investigation, and prompt and appropriate correction of noncompliance. The investigation process includes root-cause analysis of identified problems to aid in developing the corrective actions.

c. Describes a system for development, tracking, and effectiveness verification of corrective and preventative actions.

7. Environmental Training, Awareness, and Competence

a. Identifies specific education and training required for organization personnel or those acting on its behalf, as well as process for documenting training provided

b. Describes program to ensure that organization employees or those acting on its behalf are aware of its environmental policies and procedures, environmental requirements, and their roles and responsibilities within the environmental management system.

c. Describes program for ensuring that personnel responsible for meeting and maintaining compliance with environmental requirements are competent on the basis of appropriate education, training, and/or experience.

d. Identifies training on how to recognize operations and waste streams where equipment malfunctions and deterioration, and/or operator errors or deliberate malfeasance, are causing, or have the potential to cause: (1) unplanned or unauthorized releases of hazardous or harmful contaminants to the environment,

(2) a threat to human health or the environment, or (3) noncompliance with environmental requirements.

8. Environmental Planning and Organizational Decision-Making

a. Describes how environmental planning will be integrated into organizational decision-making, including plans and decisions on capital improvements, product and process design, training programs, and maintenance activities.

b. Requires establishing, on an annual basis, written targets, objectives, and action plans for improving environmental performance, by at least each operating organizational subunit with environmental responsibilities, as appropriate, including those for contractor operations conducted at the facility, and how specified actions will be tracked and progress reported. Targets and objectives must include actions that reduce the risk of noncompliance with environmental requirements and minimize the potential for unplanned or unauthorized releases of hazardous or harmful contaminants.

9. Maintenance of Records and Documentation

a. Identifies the types of records developed in support of the EMS (including audits and reviews), who maintains them and, where appropriate, security measures to prevent their unauthorized disclosure, and protocols for responding to inquiries and requests for release of information.

b. Specifies the data management systems for any internal waste tracking, environmental data, and hazardous waste determinations.

c. Specifies document control procedures.

10. Pollution Prevention

a. Describes an internal process or procedure for preventing, reducing, recycling, reusing, and minimizing waste and emissions, including incentives to encourage material substitutions. Also includes mechanisms for identifying candidate materials to be addressed by the pollution prevention program and tracking progress.

11. Continuing Program Evaluation and Improvement

a. Describes program for periodic (at least annually) evaluation of the EMS, which specifies a process for translating assessment results into EMS improvements. The program shall include communicating findings and action plans to affected organization employees or those acting on its behalf.

b. Describes a program for periodic audits (at least annually) of facility compliance with environmental requirements by an independent auditor(s). Audit results are reported to upper management and instances of noncompliance are addressed through the process described in element 6 above.

12. Public Involvement/Community Outreach

a. Describes a program for ongoing community education and involvement in the environmental aspects of the organization's operations and general environmental awareness.

Appendix B

Dominion Fixed Facilities

Dominion Facility	**Permit Number**
Bremo Power Station	VA0004138
Chesapeake Energy Center	VA0004081
Gordonsville Power Station	VA0087033
Pittsylvania Power Station	VA0083399
Possum Point Power Station	VA0002071
Southampton Power Station	VA0082767
Yorktown Power Station	VA004103
Bath County Power Station	VA0053317
Bear Garden Generating Station	VA0090891
Chesterfield Power Station	VA0004146
Hopewell Power Station	VA0082783
Mecklenburg Power Station	VA0084069
VA City Hybrid Energy Center	VA0092746

Duke Energy Carolinas
Response to
North Carolina Public Staff Data Request
Data Request No. NCPS 156

Docket No. E-7, Sub 1214

Date of Request:	**January 22, 2020**
Date of Response:	**February 3, 2020**

*Per Transcript Volume 21, page 26, lines 6-23, this document is no longer confidential. Ktm

☒ **CONFIDENTIAL**

☐ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached Confidential response to North Carolina Public Staff Data Request No. 156-2, was provided to me by the following individual(s): Trudy H. Morris, Project Manager II, and was provided to North Carolina Public Staff under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

NOTE: This response and Excel file are no longer considered confidential.

North Carolina Public Staff
Data Request No. 156
DEC Docket No. E-7, Sub 1214
Item No. 156-2
Page 1 of 2

Request:

2. Please provide a total estimated cost, including an estimated breakdown of the costs, for CCR remediation for each site and for each impoundment pursuant to the settlement agreement entered into by and between DEC and the Department of Environmental Quality.

Confidential Response:

Please see the attached response- file names:
• “CONFIDENTIAL- PS DR 156-2 DEC Ash ARO Cash Flows- Q419-as of 113019.xls”

CONFIDENTIAL- PS
DR 156-2 DEC Ash A

• “CONFIDENTIAL- PS DR 156-2 Q42019-ARO Summary of Changes 12-31-2019-v2.xls”

CONFIDENTIAL- PS
DR 156-2 Q42019-AF

• "CONFIDENTIAL- PS DR 156-2 Q42019-ARO Summary of Changes 12-31-2019-v2.xls"-This file reflects what the Q319 estimate was, the new Q419 estimate including settlement amounts and the change between both periods. File also refers to other supplemental files:
o Belews Creek Support File Name: "CONFIDENTIAL- PS DR 156-2.0 BelewsCreek.XLS"

CONFIDENTIAL- PS
DR 156-2.0 BelewsCı

o Marshall & Roxboro Support File Name: 'CONFIDENTIAL- PS DR 156-2.0 CAMA Ash_Rox_Marshall.xls"\ tab Name "Rox EAB & WEB Cash Flows"

CONFIDENTIAL- PS
DR 156-2.0 CAMA As

North Carolina Public Staff
Data Request No. 156
DEC Docket No. E-7, Sub 1214
Item No. 156-2
Page 2 of 2

o Mayo Support File Name:"CONFIDENTIAL- PS DR 156-2.0 MAYO.XLS'

CONFIDENTIAL- PS
DR 156-2.0 MAYO.xls

o Buck, HF Lee, Cape Fear (Beneficiaton sites) Support File Name: "CONFIDENTIAL- PS DR 156-2.0 Ash Beneficiation sites full vs partial excavation.xls"
DEC has provided updated cost estimates reflecting the result of the settlement agreement entered into by and between DEC and the North Carolina Department of Environmental Quality (NCDEQ).

CONFIDENTIAL- PS
DR 156-2.0 Ash Bene

The beneficiation location at Buck includes the assumption that a variance will be granted by NCDEQ to extend beneficiation activities until 2035. The basin closure dates align with the dates included in the Closure Plans submitted to NCDEQ on December 31, 2019.

Duke Energy Carolinas
Response to
North Carolina Public Staff Data Request
Data Request No. NCPS 156

Docket No. E-7, Sub 1214

Date of Request: **January 22, 2020**
Date of Response: **February 24, 2020**

☒ **CONFIDENTIAL**

☐ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached confidential supplemental response to North Carolina Public Staff Data Request No. 156-2, was provided to me by the following individual(s): Trudy H. Morris, Project Manager II, and was provided to North Carolina Public Staff under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

NOTE: This response and Excel file are no longer considered confidential.

North Carolina Public Staff
Data Request No. 156
DEC Docket No. E-7, Sub 1214
Item No. 156-2
Page 1 of 1

Request:

2. Please provide a total estimated cost, including an estimated breakdown of the costs, for CCR remediation for each site and for each impoundment pursuant to the settlement agreement entered into by and between DEC and the Department of Environmental Quality.

[redacted] Supplemental Response 2/24/2020

See updated file
CONFIDENTIAL- PS DR 156-2 DEC Ash ARO Cash Flows- Q419-as of 113019 v1.xls"
The file was updated due to an error in the actual costs in the previous spreadsheet.

CONFIDENTIAL- PS
DR 156-2 DEC Ash A

NOTE: This response and Excel file are no longer considered confidential.

Duke Energy Carolinas
Ash Management ARO Cash Flows Summary
Estimates as of Q4-2019- December 30, 2019
Actuals As of 11/30/2019
w/ inflation

[redacted]

	Total Project Costs (2015+)	Total Actuals 1/1/15 - 11/30/2019	Total CF Forecast Dec 2019- 2079	Actuals 2015	Actuals 2016	Actuals 2017	Actuals 2018	Actuals YTD Nov 2019	Forecast Dec-19
DEC									
Operating									
Allen	$ 1,143,760,913	$ 62,343,171	$ 1,081,417,742	$ 13,233,460	$ 19,430,295	$ 8,306,467	$ 15,235,608	$ 6,137,342	$ 4,981,866
Belews Creek	$ 807,048,227	$ 62,115,626	$ 744,932,601	9,861,194	26,479,748	9,534,640	7,943,584	8,296,460	3,118,400
Cliffside	$ 582,222,351	$ 75,571,228	$ 506,651,123	25,869,494	21,351,036	13,088,717	9,506,805	5,755,176	6,960,067
Marshall	$ 1,028,328,058	$ 71,911,916	$ 956,416,142	13,212,194	18,159,819	6,540,243	11,770,092	22,229,568	4,637,901
Total Operating Plants	**3,561,359,549**	**271,941,941**	**3,289,417,608**	**62,176,342**	**85,420,898**	**37,470,067**	**44,456,089**	**42,418,545**	**19,698,234**
Retired									
Buck	$ 477,849,379	$ 200,216,441	$ 277,632,938	10,035,189	9,821,833	18,828,443	63,670,317	97,860,659	21,853,515
Dan River	$ 281,226,799	$ 222,224,436	$ 59,002,363	38,612,244	70,263,998	40,266,416	29,523,242	43,558,535	6,931,956
Riverbend	$ 446,136,147	$ 414,862,785	$ 31,273,362	39,667,308	86,404,316	134,089,437	84,304,849	70,396,874	4,787,382
WS Lee (SC)	$ 274,658,595	$ 109,159,959	$ 165,498,635	19,687,325	35,344,738	37,577,688	8,498,729	8,051,480	1,213,366
Total Retired Plants	**1,479,870,919**	**946,463,621**	**533,407,298**	**108,002,066**	**201,834,885**	**230,761,985**	**185,997,137**	**219,867,548**	**34,786,219**
Total Duke Energy Carolinas	**5,041,230,468**	**1,218,405,562**	**3,822,824,906**	**$ 170,178,407**	**$ 287,255,783**	**$ 268,232,052**	**$ 230,453,226**	**$ 262,286,094**	**$ 54,484,453**

Item Labeled NCDEQ Settlement impact is the high level net impact resulting from the DEQ Settlement announced on January 2, 2020 to fully excavate all sites except Marshall & Roxboro in where those will only excavate CAMA Ash O
Refer to file names for further supplemental support:
File Name- "CONFIDENTIAL- PS DR 156-2 Q42019-ARO Summary of Changes 12-31-2019-v2.xls"-This file reflects what Q319 estimate was, new Q42019 estimate including settlement amounts and the net delta. File also refers to other
Belews Creek Support File Name: "CONFIDENTIAL- PS DR 156-2.0 BelewsCreek.XLS"
Marshall & Roxboro Support File Name: 'CONFIDENTIAL- PS DR 156-2.0 CAMA Ash_Rox_Marshall.xls"\ tab Name "Rox EAB & WEB Cash Flows"
Mayo Support File Name:"CONFIDENTIAL- PS DR 156-2.0 MAYO.XLS'
Buck, HF Lee, Cape Fear (Beneficiaton sites) Support File Name: "CONFIDENTIAL- PS DR 156-2.0 Ash Beneficiation sites full vs partial excavation.xls"

NOTE: This response and Excel file are no longer considered confidential.

Duke Energy Carolinas Ash Management ARO Cash Flows Summary Estimates as of Q4-2019- December 30, 2019 Actuals As of 11/30/2019 w/ inflation	Actuals & Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028
DEC										
Operating										
Allen	$ 11,119,207	$ 14,047,915	$ 14,114,668	$ 36,033,867	$ 41,306,069	$ 48,728,553	$ 54,644,907	$ 57,513,057	$ 61,262,020	$ 61,859,665
Belews Creek	11,414,860	17,492,927	27,909,435	41,916,386	44,266,899	43,034,208	48,805,486	54,079,224	52,018,981	53,409,840
Cliffside	12,715,243	19,613,851	31,544,508	50,912,459	48,288,407	52,824,895	53,779,439	42,008,431	23,948,195	13,739,665
Marshall	26,867,469	13,177,148	35,897,299	61,606,816	64,372,350	67,816,143	62,353,170	63,286,109	57,463,833	58,468,869
Total Operating Plants	**62,116,780**	**64,331,841**	**109,465,909**	**190,469,528**	**198,233,726**	**212,403,799**	**219,583,002**	**216,886,821**	**194,693,029**	**187,478,038**
Retired										
Buck	119,714,174	84,803,924	17,246,491	6,705,913	4,298,644	4,754,053	9,297,788	9,484,582	9,567,988	9,104,745
Dan River	50,490,491	14,128,514	3,728,665	1,126,972	1,313,540	1,082,216	1,004,956	1,025,055	1,045,556	1,066,380
Riverbend	75,184,256	1,622,940	3,251,538	778,015	917,381	667,364	614,367	626,654	639,187	651,928
WS Lee (SC)	9,264,846	8,831,986	37,653,199	17,549,154	24,825,899	29,819,973	22,727,791	2,542,808	583,104	594,709
Total Retired Plants	**254,653,768**	**109,387,364**	**61,879,893**	**26,160,054**	**31,355,465**	**36,323,606**	**33,644,901**	**13,679,100**	**11,835,835**	**11,417,762**
Total Duke Energy Carolinas	**$ 316,770,549**	**$ 173,719,206**	**$ 171,345,802**	**$ 216,629,582**	**$ 229,589,191**	**$ 248,727,405**	**$ 253,227,903**	**$ 230,565,920**	**$ 206,528,864**	**$ 198,895,801**

Item Labeled NCDEQ Settlement impact is the nly. In addition, settlement includes the assumption that a variance will be grated by NCDEQ to extend beneficaiton activities until 2035.

Refer to file names for further supplemental s

File Name- "CONFIDENTIAL- PS DR 156-2 Q42Supplemental files:

Belews Creek Support File Name: "CONFIDEN

Marshall & Roxboro Support File Name: 'CON

Mayo Support File Name:"CONFIDENTIAL- PS

Buck, HF Lee, Cape Fear (Beneficiaton sites) S

NOTE: This response and Excel file are no longer considered confidential.

Duke Energy Carolinas											
Ash Management ARO Cash Flows Summary											
Estimates as of Q4-2019- December 30, 2019											
Actuals As of 11/30/2019											
w/ inflation											
	Forecast	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
DEC											
Operating											
Allen	$ 62,988,683	$ 64,250,605	$ 65,537,874	$ 60,959,054	$ 60,700,491	$ 64,147,149	$ 68,930,966	$ 68,450,274	$ 38,331,756	$ 20,469,000	$ 8,016,269
Belews Creek	52,216,217	52,583,356	47,385,219	35,963,003	22,815,840	8,367,777	3,334,813	3,401,509	3,469,539	3,538,930	21,567,456
Cliffside	10,435,440	4,217,101	4,301,443	4,387,782	4,475,538	4,565,277	4,579,415	4,670,514	4,763,925	4,858,651	4,954,791
Marshall	59,607,997	67,018,866	68,390,798	69,060,605	53,026,829	41,279,624	2,723,664	2,778,137	2,833,700	12,002,842	12,242,899
Total Operating Plants	**185,248,336**	**188,069,927**	**185,615,334**	**170,370,445**	**141,018,698**	**118,359,827**	**79,568,859**	**79,300,435**	**49,398,920**	**40,869,423**	**46,781,415**
Retired											
Buck	6,963,161	6,644,526	6,792,213	6,644,866	12,056,864	10,179,597	9,698,470	1,173,304	1,198,215	1,223,521	1,249,257
Dan River	1,066,315	1,087,641	1,109,394	1,131,700	1,154,334	1,177,507	1,170,947	1,194,181	1,218,065	1,242,217	1,266,670
Riverbend	643,604	656,476	669,605	683,056	696,717	710,695	706,144	720,175	734,579	749,167	763,957
WS Lee (SC)	585,231	596,936	608,874	621,129	633,552	646,280	625,636	638,030	650,791	663,673	676,696
Total Retired Plants	**9,258,311**	**8,985,579**	**9,180,087**	**9,080,752**	**14,541,467**	**12,714,079**	**12,201,197**	**3,725,691**	**3,801,649**	**3,878,577**	**3,956,580**
Total Duke Energy Carolinas	**$ 194,506,647**	**$ 197,055,506**	**$ 194,795,420**	**$ 179,451,196**	**$ 155,560,165**	**$ 131,073,906**	**$ 91,770,056**	**$ 83,026,126**	**$ 53,200,568**	**$ 44,748,000**	**$ 50,737,994**
Item Labeled NCDEQ Settlement impact is the											
Refer to file names for further supplemental su											
File Name- "CONFIDENTIAL- PS DR 156-2 Q420											
Belews Creek Support File Name: "CONFIDENT											
Marshall & Roxboro Support File Name: 'CON											
Mayo Support File Name:"CONFIDENTIAL- PS											
Buck, HF Lee, Cape Fear (Beneficiaton sites) Su											

NOTE: This response and Excel file are no longer considered confidential.

Duke Energy Carolinas Ash Management ARO Cash Flows Summary Estimates as of Q4-2019- December 30, 2019 Actuals As of 11/30/2019 w/ inflation	Forecast 2040	Forecast 2041	Forecast 2042	Forecast 2043	Forecast 2044	Forecast 2045	Forecast 2046	Forecast 2047	Forecast 2048	Forecast 2049	Forecast 2050
DEC											
Operating											
Allen	$ 4,186,352	$ 4,273,777	$ 4,362,785	$ 4,695,387	$ 4,547,496	$ 4,642,947	$ 4,740,534	$ 4,840,312	$ 4,942,379	$ 5,054,930	$ 3,587,006
Belews Creek	21,397,363	3,755,541	3,830,652	3,907,265	3,985,410	4,065,118	4,146,421	4,229,349	4,313,936	4,400,215	2,892,580
Cliffside	5,132,072	5,155,736	5,258,259	5,363,425	5,470,910	5,580,328	5,691,935	5,805,774	20,436,305	6,108,783	3,986,055
Marshall	3,007,145	3,067,288	3,128,634	3,191,206	3,255,031	3,320,131	3,386,534	3,454,265	3,523,350	3,593,817	2,512,120
Total Operating Plants	**33,722,932**	**16,252,341**	**16,580,330**	**17,157,283**	**17,258,847**	**17,608,524**	**17,965,423**	**18,329,699**	**33,215,970**	**19,157,745**	**12,977,761**
Retired											
Buck	1,276,157	1,303,439	1,331,169	1,432,114	1,388,978	1,418,900	1,449,527	1,480,882	1,513,005	1,550,260	1,594,995
Dan River	1,292,289	1,318,135	1,344,274	1,371,159	1,398,665	1,426,638	1,455,171	1,484,274	1,513,986	678,451	124,838
Riverbend	779,378	794,965	810,754	826,969	843,549	860,420	877,628	895,181	913,097	933,948	124,838
WS Lee (SC)	690,413	704,221	718,163	732,526	747,229	762,174	777,417	792,966	808,842	828,359	853,296
Total Retired Plants	**4,038,237**	**4,120,761**	**4,204,359**	**4,362,768**	**4,378,421**	**4,468,131**	**4,559,744**	**4,653,302**	**4,748,930**	**3,991,018**	**2,697,968**
Total Duke Energy Carolinas	**$ 37,761,169**	**$ 20,373,102**	**$ 20,784,689**	**$ 21,520,051**	**$ 21,637,268**	**$ 22,076,656**	**$ 22,525,167**	**$ 22,983,002**	**$ 37,964,900**	**$ 23,148,763**	**$ 15,675,729**

Item Labeled NCDEQ Settlement impact is the
Refer to file names for further supplemental su
File Name- "CONFIDENTIAL- PS DR 156-2 Q42(
Belews Creek Support File Name: "CONFIDEN
Marshall & Roxboro Support File Name: 'CON
Mayo Support File Name:"CONFIDENTIAL- PS
Buck, HF Lee, Cape Fear (Beneficiaton sites) Su

NOTE: This response and Excel file are no longer considered confidential.

Duke Energy Carolinas												
Ash Management ARO Cash Flows Summary												
Estimates as of Q4-2019- December 30, 2019												
Actuals As of 11/30/2019												
w/ inflation												
	Forecast	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
	2051	**2052**	**2053**	**2054**	**2055**	**2056**	**2057**	**2058**	**2059**	**2060**	**2061**	**2062**
DEC												
Operating												
Allen	$ 3,667,123	$ 3,749,590	$ 3,840,558	$ 3,934,960	$ 4,054,931	$ 4,200,586	$ 2,540,392	$ 2,599,749	$ 2,660,727	$ 2,359,958	$ 2,407,158	$ 2,455,301
Belews Creek	2,950,431	3,009,440	3,069,629	3,131,021	3,193,642	3,257,515	3,322,665	3,389,118	3,456,901	3,526,039	3,596,559	3,668,490
Cliffside	4,069,522	4,155,370	4,253,452	4,355,555	4,497,276	2,084,406	2,140,475	373,469	416,267	292,235	298,080	304,042
Marshall	2,562,363	2,613,610	2,665,882	2,719,200	2,773,584	2,829,055	2,885,637	2,943,349	3,002,216	3,062,261	3,123,506	3,185,976
Total Operating Plants	**13,249,438**	**13,528,010**	**13,829,520**	**14,140,737**	**14,519,432**	**12,371,562**	**10,889,168**	**9,305,686**	**9,536,111**	**9,240,493**	**9,425,303**	**9,613,809**
Retired												
Buck	1,631,136	1,571,828	1,611,282	1,652,351	1,706,553	1,773,944	1,887,484	1,998,701	2,225,206	775,729	791,243	807,068
Dan River	32,979	33,639	34,312	34,998	35,698	36,412	37,140	37,883	38,641	-	-	-
Riverbend	32,979	33,639	34,312	34,998	35,698	36,412	37,140	37,883	38,641	-	-	-
WS Lee (SC)	871,399	890,062	912,009	934,966	35,698	36,412	37,140	37,883	38,641	-	-	-
Total Retired Plants	**2,568,495**	**2,529,168**	**2,591,915**	**2,657,314**	**1,813,647**	**1,883,180**	**1,998,904**	**2,112,350**	**2,341,128**	**775,729**	**791,243**	**807,068**
Total Duke Energy Carolinas	**$ 15,817,933**	**$ 16,057,177**	**$ 16,421,436**	**$ 16,798,051**	**$ 16,333,079**	**$ 14,254,742**	**$ 12,888,073**	**$ 11,418,036**	**$ 11,877,239**	**$ 10,016,222**	**$ 10,216,546**	**$ 10,420,877**
Item Labeled NCDEQ Settlement impact is the												
Refer to file names for further supplemental su												
File Name- "CONFIDENTIAL- PS DR 156-2 Q42(												
Belews Creek Support File Name: "CONFIDEN												
Marshall & Roxboro Support File Name: 'CON												
Mayo Support File Name:"CONFIDENTIAL- PS												
Buck, HF Lee, Cape Fear (Beneficiaton sites) Su												

NOTE: This response and Excel file are no longer considered confidential.

Duke Energy Carolinas														
Ash Management ARO Cash Flows Summary														
Estimates as of Q4-2019- December 30, 2019														
Actuals As of 11/30/2019														
w/ inflation														
	Forecast	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
	2063	**2064**	**2065**	**2066**	**2067**	**2068**	**2069**	**2070**	**2071**	**2072**	**2073**	**2074**	**2075**	**2076**
DEC														
Operating														
Allen	$ 2,504,407	$ 2,554,495	$ 2,605,585	$ 2,657,696	$ 2,710,850	$ 2,765,067	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Belews Creek	3,741,860	-	-	-	-	-	-	-	-	-	-	-	-	-
Cliffside	310,123	316,325	322,652	329,105	335,687	342,400	349,248	356,233	363,358	370,625	378,038	385,598	393,310	401,177
Marshall	3,249,695	3,314,689	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating Plants	**9,806,085**	**6,185,509**	**2,928,236**	**2,986,801**	**3,046,537**	**3,107,468**	**349,248**	**356,233**	**363,358**	**370,625**	**378,038**	**385,598**	**393,310**	**401,177**
Retired														
Buck	823,209	839,674	856,467	-	-	-	-	-	-	-	-	-	-	-
Dan River	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Riverbend	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WS Lee (SC)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Retired Plants	**823,209**	**839,674**	**856,467**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total Duke Energy Carolinas	**$ 10,629,294**	**$ 7,025,183**	**$ 3,784,703**	**$ 2,986,801**	**$ 3,046,537**	**$ 3,107,468**	**$ 349,248**	**$ 356,233**	**$ 363,358**	**$ 370,625**	**$ 378,038**	**$ 385,598**	**$ 393,310**	**$ 401,177**
Item Labeled NCDEQ Settlement impact is the														
Refer to file names for further supplemental su														
File Name- "CONFIDENTIAL- PS DR 156-2 Q42(														
Belews Creek Support File Name: "CONFIDEN														
Marshall & Roxboro Support File Name: 'CON														
Mayo Support File Name:"CONFIDENTIAL- PS														
Buck, HF Lee, Cape Fear (Beneficiaton sites) Su														

Duke Energy Carolinas			
Ash Management ARO Cash Flows Summary			
Estimates as of Q4-2019- December 30, 2019			
Actuals As of 11/30/2019			
w/ inflation			
	Forecast	**Forecast**	**Forecast**
	2077	**2078**	**2079**
DEC			
Operating			
Allen	$ -	$ -	$ -
Belews Creek	-	-	-
Cliffside	409,200	228,514	-
Marshall	-	-	-
Total Operating Plants	**409,200**	**228,514**	**-**
Retired			
Buck	-	-	-
Dan River	-	-	-
Riverbend	-	-	-
WS Lee (SC)	-	-	-
Total Retired Plants	**-**	**-**	**-**
Total Duke Energy Carolinas	**$ 409,200**	**$ 228,514**	**$ -**
Item Labeled NCDEQ Settlement impact is the			
Refer to file names for further supplemental su			
File Name- "CONFIDENTIAL- PS DR 156-2 Q420			
Belews Creek Support File Name: "CONFIDEN'			
Marshall & Roxboro Support File Name: 'CONI			
Mayo Support File Name:"CONFIDENTIAL- PS			
Buck, HF Lee, Cape Fear (Beneficiaton sites) Su			

NOTE: This response and Excel file are no longer considered confidential.

DUKE ENERGY.

Brian D. Savoy
SVP, Chief Accounting Officer and Controller
550 South Tryon Street
Mail Code: DEC 44-A
Charlotte, NC 28202
o 704-382-6242
f 980-373-6797

December 21, 2015

E-7 SUB 1110
E-2 SUB 1103

Ms. Gail L. Mount
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

RE: Explanation of Accounting Treatment Related to Coal Ash Basin Obligations

Dear Ms. Mount:

Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC") (collectively, the "Companies") respectfully notify the Commission of certain accounting entries, which are consistent with Generally Accepted Accounting Principles ("GAAP"), Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts and General Instruction No. 25, and regulatory accounting practices related to the establishment of certain Asset Retirement Obligations ("AROs") associated with federal and state requirements related to coal ash management and ash basin closure costs. The Companies also notify the Commission of their treatment of actual expenditures related to compliance with such federal and state requirements, and the establishment of a regulatory asset for such expenditures.

Description of Requirements Giving Rise to the AROs

In accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification for Asset Retirement and Environmental Obligations ("ASC 410-20") and FERC General Instruction No. 25, each of the Companies records an ARO when it has a legal obligation to incur retirement costs associated with the retirement of a long-lived asset and the obligation can be reasonably estimated. These accounting requirements dictate the measurement and recognition of AROs for companies in general. The Commission has issued orders allowing the Companies to defer all impacts of establishing an ARO until these costs can be considered in future rate making decisions.[1] In addition, DEP's rates currently include a component for ash remediation costs as a part of Cost of Removal included in depreciation rates; however, only a small balance has been collected for such costs since DEP's last retail rate case in North Carolina.

In April 2015, the Environmental Protection Agency ("EPA") published in the Federal Register a rule to regulate the disposal of Coal Combustion Residuals ("CCRs") from electric utilities as solid waste.[2] The federal regulation classifies CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act and allows beneficial use of CCRs with some restrictions. The federal regulation applies to all new and existing landfills, new and existing surface impoundments, structural fills and CCR piles. The federal regulation establishes requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to ensure the safe disposal and management of CCR. In addition to the

[1] *In the Matter of Duke Power's Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account*, NCUC Docket No. E-7, Sub 723, *Order Granting Motion for Reconsideration and Allowing Deferral of Costs* (August 8, 2003); and *In the Matter of Carolina Power & Light Company's Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account*, NCUC Docket No. E-2, Sub 826, *Order Granting Motion for Reconsideration and Allowing Deferral of Costs* (August 12, 2003).

[2] Hazardous and Solid Waste Management system: Disposal of Coal Combustion Residuals from Electric Utilities promulgated by the United States Environmental Protection Agency ("EPA") and published on April 17, 2015, 80 Fed Reg. 21302 ("CCR rule").

requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by most states, including North Carolina.

In September 2014, the North Carolina Coal Ash Management Act (the "Coal Ash Act") 2014 N.C. Sess. Laws 122; 2014 N.C. Ch. 122; 2013 N.C. SB 729, became law and was amended in June 2015, by the Mountain Energy Act. The Coal Ash Act, as amended,

(i) establishes a Coal Ash Management Commission ("Coal Ash Commission")[3] to oversee handling of coal ash within the state;

(ii) prohibits construction of new and expansion of existing ash impoundments and use of existing impoundments at retired facilities;

(iii) requires closure of ash impoundments at DEP's Sutton Plant and DEC's Riverbend and Dan River stations no later than August 1, 2019 and DEP's Asheville Plant no later than August 1, 2022;

(iv) requires dry disposal of fly ash at active plants, excluding the Asheville Plant, not retired by December 31, 2018;

(v) requires dry disposal of bottom ash at active plants, excluding the Asheville Plant, by December 31, 2019, or retirement of active plants;

(vi) requires all remaining ash impoundments in North Carolina to be categorized as high-risk, intermediate-risk or low-risk no later than December 31, 2015 by the North Carolina Department of Environment Quality ("DEQ," formally known as the NC Department of Environmental and Natural Resources, or "DENR") with the method of closure and timing to be based upon the assigned risk, with closure no later than December 31, 2029;

(vii) establishes requirements to deal with groundwater and surface water impacts from impoundments; and

(viii) enhances the level of regulation for structural fills utilizing coal ash.

[3] The structure of the Coal Ash Commission has been challenged as a violation of the constitutional separation of powers between the Executive Branch and the General Assembly. A decision by the N.C. Supreme Court is pending. Depending on the result, the decision could place doubt on previous actions by the Coal Ash Commission.

The Coal Ash Act includes a variance procedure for compliance deadlines and modification of requirements regarding structural fills and compliance boundaries. The Companies have and will periodically submit to DEQ site-specific coal ash impoundment closure plans or excavation plans in advance of closure. These plans and all associated permits must be approved by DEQ before any excavation or closure work can begin.

In 2014 and 2015, DEC executed consent agreements with the South Carolina Department of Health and Environmental Control ("SCDHEC") and conservation groups requiring the excavation of an inactive ash basin and ash fill area at the W.S. Lee Steam Station. In July 2015, DEP executed a consent agreement with the SCDHEC requiring the excavation of an inactive ash fill area at the Robinson Plant within eight years. The W.S. Lee Station site and the Robinson Plant are required to be closed pursuant to the recently issued federal CCR rule and/or the provisions of these consent agreements which are consistent with the federal CCR closure requirements described above.

Accounting for Coal Ash Basin AROs

AROs are legal obligations associated with the retirement of a tangible long-lived asset that results from the acquisition, construction, or development and (or) the normal operation of a long-lived asset and also include environmental remediation liabilities that result from the normal operation of a long-lived asset and that is associated with the retirement of that asset. AROs recorded on the DEC and DEP Balance Sheets at November 30, 2015 are based upon the legal obligation for closure of coal ash basins and the disposal of related ash as a result of the federal and state requirements described above, and total approximately $1.84 billion for DEC and approximately $2.13 billion for DEP. These AROs are included in the Companies' financials as allowed by NCUC Docket No. E-7, Sub 723, Order dated August 8, 2003 and

NCUC Docket No. E-2, Sub 826, Order dated August 12, 2003. The actual compliance costs incurred may be materially different from these estimates based on the timing and requirements of the final regulations.

Liabilities Recorded Related to the AROs

The Companies measure and recognize AROs in accordance with ASC 410-20 (previously Statement of Financial Accounting Standards "SFAS" No. 143). ASC 410-20 requires that the fair value of a liability for an ARO be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. As such, the coal ash ARO liability balance as of November 30, 2015 is based on the initial liability recognized in September 2014 upon the passage of the Coal Ash Act, as adjusted for accretion expense (discussed further below), cash settlements, and remeasurements of the liability. Remeasurements to the liability are due to revisions in either the timing or the amount of the original estimate of undiscounted cash flows. Typically, remeasurements occur when there are significant new events and information (e.g., passage of the federal CCR regulation, changes to closure plans, etc.) used by management in the estimation of future expected cash outflows.

The ARO was initially calculated, along with subsequent remeasurements and additions to the liability, using an expected present value technique of probability weighted discounted cash flows. These cash flows were based on management's best estimate of projected cash flows and legal interpretation of the various federal and state requirements described above. As the obligations can be satisfied by various compliance alternatives selected based on management's site-specific risk assessments over various timeframes, the uncertainty surrounding the obligations was factored into the ARO recognition by assessing the likelihood (probability) that a certain type of compliance method would be required.

These estimated cash flows, along with various other financial assumptions required by ASC 410-20 (including inflation and discount rates, profit margin and risk premium) were used to properly measure the AROs on the balance sheet at fair value, as defined by GAAP.

Because the liability is based on a present value calculation using many assumptions, including a credit-adjusted risk-free discount rate, the liability will grow simply from the passage of time. This increase to the liability is known as accretion. From January 1, 2015 to November 30, 2015, accretion totaled $59 million and $65 million for DEC and DEP, respectively.

Assets Associated with the Liability Recorded Related to the AROs

At the time the ARO liability is recorded, a corresponding and equivalent ARO asset is recorded on the books, as part of the cost of the associated coal plant in the property, plant and equipment ("PP&E") accounts, or if associated with a retired coal plant, recorded in regulatory assets. The ARO PP&E balance is depreciated over the remaining estimated plant lives, and such depreciation expenses is deferred into regulatory asset accounts. From January 1, 2015 to November 30, 2015, ARO depreciation totaled $217 million and $325 million for DEC and DEP, respectively. Additionally, as discussed above, accretion is added to the ARO liability each reporting period to account for the time value of money, so that at the time of retirement, the recorded ARO liability will be sufficient to provide for the cash outlays necessary to meet the legal obligation. Thus, the ARO expense recorded each year generally includes two components: depreciation expense associated with the ARO asset on active plants and accretion expense measuring the change in the total ARO liability due to the time value of money. Consistent with the requirements of the Commission's Order dated August 8, 2003 in Docket No. E-7, Sub 723 and Order dated August 12, 2003 in Docket No. E-2, Sub 826, all income statement impacts related to AROs ultimately reside in regulatory asset accounts.

The FASB recognized that differences may exist between the requirements of ASC 410-20 and the treatment of ARO cost for regulatory purposes, and accordingly, provided that a regulated entity subject to ASC 980, *Regulated Operations*, (formerly SFAS 71, *Accounting for the Effects of Certain Types of Regulation*), could recognize a regulatory asset or liability for any differences between the two approaches, if the facts and circumstances meet the requirements of ASC 980 for such recognition.

Net Asset Balance Primarily Relates to Cash Expenditures

As of November 30, 2015, PP&E (active plants) and regulatory assets (inactive plants) related to coal ash basin AROs total approximately $4.19 billion, combined for both categories of assets and DEC and DEP. The related asset retirement obligation liabilities total approximately $3.97 billion, resulting in a net asset balance of approximately $220.5 million. Of this amount, $231.9 million relates to cash expenditures incurred in 2015 associated with ash basin closure, and $2.7 million relates to carrying costs, partially offset primarily by recoveries through existing DEP cost of removal rates.

As a result of the deferral accounting applied to this ARO liability, actual costs incurred to comply with the federal and state regulations regarding closure of ash basins are being deferred. As coal ash basin closure compliance costs are incurred, the Companies are reducing the ARO liability and the associated ARO regulatory asset described above, while simultaneously creating a corresponding separate regulatory asset that represents actual cash expenditures incurred. As the Companies are excluding all associated coal ash ARO deferrals for earnings surveillance reporting and are funding these expenditures with its debt and equity capitalization, the Companies are recording a debt and equity return ("carrying charge") on the aforementioned net asset for regulatory purposes. GAAP requires the equity return to be deferred (i.e., not recognized) until rate recovery has begun, and thus the only carrying charge recorded to date for GAAP purposes is the debt return, which totals approximately $2.7 million combined for the Companies through November 30, 2015. Ultimately, only actual costs resulting in cash outlays by the Companies related to ash basin closure, plus carrying charges, will result in amounts for which the Companies will request accounting and recovery treatment in future filings before this Commission. Coal ash basin costs that relate to activities outside the scope of the aforementioned legally required activities (e.g., Federal CCR rules and the NC CAMA legislation) are being expensed immediately as Operations and Maintenance ("O&M") expense. In addition, capital conversion costs such as those related to conversion to dry or fly ash equipment are recorded in Construction Work in Progress.

The Companies do not seek any further specific accounting approval at present due to the uncertainties in North Carolina regarding the closure costs of coal ash basins. Actual costs to be incurred will be dependent upon factors that vary from site to site. The most significant factors are the method and time frame of closure at the individual sites. Closure methods considered include removing the water from the basins and capping the ash with a synthetic barrier, excavating and relocating the ash to a lined structural fill or lined landfill, or recycling the ash for concrete or some other beneficial use. Under the previously cited Coal Ash Act, DEQ is required to prioritize sites by December 31, 2015. That process has not been completed. Once the DEQ determinations are made, the Companies will need to evaluate the recommendation and develop more specific cost estimates. The ultimate method and timetable for closure will be in compliance with standards set by the EPA rule and any state regulations. The ARO estimates will be adjusted as additional information is gained through the closure process, including acceptance and approval of compliance approaches which may change management assumptions, and may result in a material change to the recorded ARO. In addition, on March 5, 2015, Governor McCrory filed a lawsuit challenging the constitutionality of the Coal Ash Commission. That case is currently pending before the North Carolina Supreme Court.[4] Pending a decision in that case, activity by the Coal Ash Commission has been suspended. Further, if the Court should rule that the actual structure of the Coal Ash Commission violates the constitutional provision of the separation of powers, the lawfulness of previous actions by the Commission could be subject to legal challenge.

The Companies provide this explanation of their accounting for the above-described ash basin closure and compliance costs for the Commission's information at this time. At a later date, when there is sufficient clarity in North Carolina regarding the closure of ash basins, the Companies will bring this matter before the Commission for ultimate disposition.

If you have any questions, please let me know.

Sincerely,

Brian D. Savoy
Senior Vice President, Chief Accounting Officer and Controller

cc: Antoinette R. Wike
Christopher J. Ayers
Chairman Edward S. Finley, Jr
Commissioner Don M. Bailey
Commissioner Bryan E. Beatty
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Susan Warren Rabon

[4] *Patrick L. McCrory, et al v. Phillip E. Berer, et al. NC Supreme Court,* Case No. 113A15 (2015).

From: Stowe, Allen
Sent: Friday, April 19, 2013 1:43 PM
To: Watts, Debra
Cc: Toepfer, John; Smith, Eric; Wilcox, Betty
Subject: RE: Ash Pond Closure Draft

Debra,

Attached are our consolidated comments on ash pond closure guidelines and closure letter. We very much appreciate the opportunity to review and provide input. If possible, we would like to review the revised documents before they are finalized as well.

Please let me know if you have any questions or comments regarding these documents.

Thanks

Allen Stowe
Water & Natural Resources
Duke Energy
704-382-4309 (Office)
704-516-5548 (Cell)
Allen.Stowe@duke-energy.com

From: Watts, Debra [mailto:debra.watts@ncdenr.gov]
Sent: Tuesday, March 26, 2013 5:55 PM
To: Stowe, Allen
Cc: Toepfer, John; Smith, Eric; Wilcox, Betty; Hickok, Linda; Brown, Kevin; Zarzar, Issa; Sullivan, Ed M; Ed Henriques
Subject: Ash Pond Closure Draft

Allen

As discussed, the APS staff has developed ash pond closure guidelines over the past year. Much of this was based on what you presented during our Weatherspoon closure meetings, so you shouldn't be too surprised as to what we are sending you. The policy letter is titled "Ash Pond Closure Letter 3-26-13 Final Draft…" and the list of requirements (attachment to the policy) is titled "Draft Closure Requirements 3-25-13."

Ted has seen this although he has not signed it. We are looking at receiving feedback from our stakeholders, Duke and the former Progress Energy, before going forward with this. The Environmental Groups will also be asked for feedback, and will receive a copy of this after we incorporate any changes you may have.

We would appreciate you distributing this to whomever it needs to be seen by. Also, we'd like to have your consolidated comments by April 19th (3 weeks), but if you need more time, please let us know.

Thanks for your assistance with this. Let us know if you have any questions.

Debra J. Watts, Supervisor
Groundwater Protection Unit
Aquifer Protection Section

[redacted]

919-807-6338

[redacted]

Ash Pond Closure Plan Requirements

The purpose of the following outline is to aid in the development of an ash pond closure plan. These plans must be submitted to the Aquifer Protection Section (APS) Chief for approval.

1) Facility and Ash Pond Description. Briefly describe or provide the following:
   a) Site and history of site operations.
   b) Ash handling and storage operations.
   c) Types of flows discharging into the pond (e.g. ash transport water, stormwater runoff, chemical and non-chemical metal cleaning wastewaters, coal pile runoff, miscellaneous equipment cooling and lubricating water, etc.)
   d) Estimated volume of material contained in the ash pond(s).
   e) Analysis of the structural integrity of dikes and/or dams associated with ash pond.
   f) Composition of liner (lined or unlined pond).
   g) Summarized results of any previous environmental investigations performed at the site.
2) Site Map. Provide a site map that illustrates the following:
   a) All structures associated with operations of the ash ponds within the power plant property boundary.
   b) All identified current and former ash disposal and storage areas including structural fills.
   c) All property boundaries and established compliance boundaries.
   d) All known potential receptors (i.e. water supply wells, surface water bodies (streams, springs, lakes, ponds and other surface drainage features), and wetlands) within 1500 feet of the ash pond boundary.
   e) Topographic contours of the site (no less than 5 ft. intervals).
   f) Locations of all on-site active and inactive Division of Waste Management (DWM) permitted solid waste facilities along with their associated compliance boundaries and monitoring wells.
   g) All existing and proposed groundwater monitoring wells associated with monitoring of the active and inactive ash ponds.
   h) All existing and proposed sample collection locations associated with the operation or closure of the ash pond(s).
3) Hydrogeologic, Geologic, and Geotechnical Investigation. Refer to the Policy for Hydrogeologic Investigation and Reporting dated May 31, 2007. Provide the following:
   a) A brief description of the hydrogeology and geology of the site.
   b) A description of the stratigraphy of the geologic units underlying the ash ponds.
   c) The saturated hydraulic conductivity for the ash, liner (if present), and all identified stratigraphic units underlying the ash pond(s).
   d) The geotechnical properties for the ash, liner (if present), and the uppermost identified stratigraphic unit underlying the ash pond(s). Analyses should include the following:
      i) Soil Classification by Unified Soil Classification System
      ii) In-place moisture content

[redacted]

iii) Particle size distribution
iv) Atterberg limits
v) Specific gravity
vi) Effective friction angle
vii) Maximum dry density
viii) Optimum moisture content
ix) Permeability

e) Provide laboratory results for chemical analysis of the ash basin pond water, ash, and ash-affected soil. Identify constituents with concentrations found to be in excess of 15A NCAC 02L.0202 Groundwater Quality Standards.

f) A map that illustrates the following:
i) potentiometric contours and flow directions for all identified aquifers underlying the ash pond(s) (shallow, intermediate, and deep).
ii) the known horizontal extent of areas where 15A NCAC 02L.0202 Groundwater Quality Standards are exceeded.

g) Cross-sections that illustrate the following:
i) Vertical and horizontal extent of the ash within the ash pond
ii) Stratigraphy of the geologic units underlying the ash pond.
iii) the vertical extent of areas where 15A NCAC 02L.0202 Groundwater Quality Standards are exceeded.

4) Hydrogeologic Modeling. Please refer to the Groundwater Modeling Policy and Reporting Policy dated May 31, 2007.

a) Perform groundwater modeling based on the design of the proposed pond closure method.

b) The groundwater modeling should:
i) be based on the site hydrogeologic conceptual model developed using the Hydrogeologic Investigation and Reporting Policy.
ii) provide predictions on post-closure groundwater elevations, groundwater flow directions and velocities
iii) provide predictions at the compliance boundary for constituents identified in part 3 (e) as exceeding 15A NCAC 02L.0202 Groundwater Quality Standards.

c) If required, describe the actions necessary to demonstrate compliance with 15A NCAC 02L.0202 Groundwater Quality Standards and 15A NCAC 02L .0106, as applicable.

5) Closure Method

a) Provide a description of the closure method. Closure methods include:
i) Closure-in-Place. This alternative entails placing an engineered cover system such as a composite geomembrane, impermeable clay, and/or a soil cover over the ash pond. No ash or ash-affected soil would leave the ash pond area.
ii) Clean Closure. This alternative assumes that all coal ash can be excavated and the ash pond area will be returned to a non-erosive and stable condition.
iii) Hybrid Closure. This alternative entails consolidating ash and ash-affected soil into as small area as feasable within the ash pond footprint. An engineered cover system (e.g. composite geomembrane, impermeable

[redacted]

clay, and/or a soil cover) would be installed over the consolidated ash and ash-affected soil. The remaining ash pond area will be returned to a non-erosive and stable condition.

iv) Other closure methods as approved by the Aquifer Protection Section Chief. These methods must be demonstrated to be effective at protecting water quality.

b) Provide any plans for beneficial reuse of the coal ash under 15A NCAC 02T .1200 (if applicable).

c) Identify the closure method for the ash pond(s).

d) Provide all engineering drawings, schematics, and specifications for the proposed closure method.

   i) If required by G.S. 89C, engineering design documents should be prepared, signed, and sealed by a professional engineer.

   ii) Describe the construction quality assurance and quality control program including:

      A) responsibilities and authorities;
      B) monitoring and testing activities; and
      C) sampling strategies
      D) reporting requirements

e) Describe the provisions for disposal of wastewater through the NPDES permit or any other relevant permit. The facility needs to meet all the requirements of the NPDES wastewater permit during the dewatering of the ash pond.

f) Describe the provisions for disposal or removal of ash. Identify the site and the permit number for ash sent to a permitted disposal site. If ash is left in place:

   i) Describe how the ash will be stabilized during closure and post closure.
   ii) Estimate the volume of ash left in place.

g) Identify all permits that are necessary (i.e. permits that will need to be acquired or modified) to complete closure activities.

6) Post-Closure Plan. Post-Closure Plans should be designed for a minimum of 30 years. If required by G.S. 89C, these plans should be signed and sealed by a professional engineer.

a) Describe the post-closure care and maintenance activities.

b) Demonstrate the long-term control of all leachate, affected groundwater, and stormwater

c) Describe the Groundwater Monitoring Program, to include:

   i) Post closure groundwater monitoring including parameters to be sampled and sampling schedules

   ii) Any additional monitoring well/s installations, including a map with the proposed location/s and well construction details.

e) The length of the post-closure care period may be decreased and/or the frequency and parameter list may be modified by the Section if the owner demonstrates that the reduced period and/or modifications are sufficient to protect human health and the environment and this demonstration is approved by the Section.

f) Following completion of the post-closure care period, the owner shall notify the Section that a certification, signed by a registered professional engineer, verifying that post-closure care has been completed in accordance with the post-closure plan, has been placed in the file.

[redacted]

7) Schedules
   a) Provide an estimate of the milestone dates for all activities related to closure and post-closure..
8) Future Site Use
   a) Describe the anticipated future site use.
   b) Determine the necessity for deed restrictions following closure.

[redacted]

I/A

NCDENR

North Carolina Department of Environment and Natural Resources

Division of Water Quality

Pat McCrory Governor	Charles Wakild, P. E. Director	John E. Skvarla, III Secretary

March XX, 2013

MEMORANDUM

TO: Aquifer Protection Section Staff
Surface Water Protection Section Staff
Interested Parties

THROUGH: Jay Zimmerman, P.G.
Aquifer Protection Section Chief

THROUGH: Matt Matthews
Surface Water Protection Section Chief

FROM: Ted L. Bush, Jr.
Deputy Director

SUBJECT: Guidelines for the Closure of Ash Ponds

<u>Purpose</u>

The purpose of these guidelines is to provide a course of action for the closure of ash ponds at coal-fired power plant facilities permitted by the Division of Water Quality (DWQ). There are fourteen (14) major existing or recently retired coal-fired power plants in North Carolina that are regulated under North Carolina General Statute 143.215.1. These same facilities are further regulated by 15A NCAC 2L, *Classifications and Water Quality Standards Applicable to the Groundwaters of North Carolina*, but are not regulated as a solid or hazardous waste.

In order to develop guidelines for ash pond closures, the Aquifer Protection Section (APS) researched and incorporated elements from the North Carolina Division of Waste Management (DWM) Solid Waste Rules, the Environmental Protection Agency (EPA), and other State guidelines and rules. Although corrective action is not the focus of these guidelines, closure of these structures can be considered an important tool if corrective action is required. However, the basis of these guidelines is to assist permittees in obtaining a closure approval from DWQ.

<u>Closure Plan Approval</u>

Each coal ash facility presents a unique set of challenges for closure due to their size, complexity, and location. Therefore, to allow the most flexibility in solutions to these challenges, the attached guidelines only outline the requirements versus spelling out specific

[redacted]

details, thus facilitating the decisions the permittee may need to make to determine the best way to meet these requirements. A closure plan must still be submitted that details all aspects of the closure and post-closure activities at the facility, and should include the following elements:

- Facility and Ash Pond Description
- Site Maps
- Hydrogeologic, Geologic, and Geotechnical Investigation
- Closure Method
- Hydrogeologic Modeling
- Post-closure plan
- Schedules
- Future Site Use

Once the closure plan is developed, the permittee of the facility must submit this plan along with a letter to the APS Section Chief requesting closure.

<u>Optional Pre-Submittal Meeting</u>
Although a complete plan is required before approval can be obtained, a pre-submittal meeting is highly encouraged where the applicant must provide a minimum portion of the application (e.g. facility and ash pond description; site maps; and hydrogeologic, geologic, and geotechnical investigation) in addition to the chosen method of closure. Past DWQ experience has shown that pre-submittal meetings have been very beneficial to improving review timeliness since applications tend to be more complete. In addition, the pre-submittal meeting provides an opportunity to discuss the project in general, the history of the site, design considerations, and any initial questions the reviewers may have. Once the applicant and reviewers have had a chance to meet, the applicant must submit their complete closure request for approval as discussed above.

<u>Submittal Requirements</u>
The requestor should submit five (5) copies of the closure plan to the APS Section Chief and an electronic copy (not via email). The APS Section Chief will then distribute the copies to the appropriate agencies.

<u>Closure Plan Review</u>
The closure plan will be reviewed by a technical review committee selected by the APS Section Chief. The committee will generally consist of engineers, geologists and APS regional and central office representatives, to include the APS Regional Supervisor of the closure site. After thorough review of the closure plan and coordination with the DWQ National Pollutant Discharge Elimination System (NPDES) staff, the committee will present their recommendations to the APS Section Chief. The APS Section Chief will then send a letter recommending approval or denial of the closure request through the Surface Water Protection Section (SWPS) Chief to the DWQ Deputy Director. The Deputy Director will send a letter to the applicant that conveys approval or denial of the closure request. If the letter conveys denial, sufficient justification for the decision will be included. If the letter conveys approval, the requestor may begin the closure activities.

[redacted]

Additional Requirements
While the intent of this policy is to assist permittees in obtaining a closure approval for their permitted ash pond, this does not give them approval for decommissioning the dam. Permittees must apply separately for dam decommissioning with the Division of Energy, Mineral, and Land Resources (DEMLR). Since a number of the technical requirements for ash pond closure and dam decommissioning are the same, it may be acceptable to submit the same closure plan to DEMLR. Due to extensive grading work and potential for sedimentation anticipated during closure, an Erosion and Sedimentation control plan may need to be submitted to DEMLR as well (reference Sedimentation Pollution Control Act of 1973).

Closure Activities
Once the entire closure plan has been accepted by all State entities involved, the applicant may proceed with the proposed closure activities. The APS Regional Office will oversee the ash pond closure activities and perform inspections as needed.

Attachment:
Ash Pond Closure Requirements

cc: DWQ/Surface Water Protection Section (Matt Matthews)
DWQ/ Surface Water Protection Section /NPDES (Tom Belnick)
DEMLR/Land Quality Section (Steve McEvoy)
DWM/Solid Waste Section (Ed Mussler)

[redacted]

INDEX TO DORGAN EXHIBIT 1

INDEX TO DORGAN EXHIBIT 1

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
REVENUE IMPACT OF PUBLIC STAFF ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 1

Line No.		Amount
1	Revenue requirement increase per Company application, base rates	$ 585,961 1/
2	Revenue impact of Company updates	-
3	**Revenue requirement increase per Company after updates**	**$ 585,961**
4	Revenue impact of Public Staff adjustments: 2/	
5	Change in equity ratio from 53 00% to 50 00% equity	($30,045)
6	Change in debt cost rate from 4.155% to 4.110%	(2,412)
7	Change in return on equity from 10.30% to 9.00%	(91,586)
8	Adjust for cost of service reallocations - SWP&A	(16,267)
9	Update plant and accumulated depreciation to December 31, 2019	(43,798)
10	Update revenues, customer growth, and weather to December 31, 2019	(8,892)
11	Adjust payment card fees	(91)
12	Remove Unprotected Federal, State EDIT, and deferred Federal from base rates for treatment as a rider	42,907 3/
13	Adjust for flowback of Protected Federal EDIT due to Tax Cuts and Jobs Act	(29,829)
14	Adjust aviation expenses	(409)
15	Adjust executive compensation	(161)
16	Adjust salaries & wage expense	2,048
17	Adjust outside services	(146)
18	Adjust rate case expense	(560)
19	Adjust to normalize storm costs	9,334
20	Adjust to remove storm deferral	(84,151)
21	Adjust for severance costs	(6,402)
22	Adjust depreciation rates	(40,337)
23	Adjust incentives	(14,705)
24	Adjust deferred environmental costs	(111,865)
25	Adjust deferred non-ARO environmental costs	(3,787)
26	Adjust Asheville CC Plant in Service	(5,459)
27	Adjust Asheville CC deferral	(5,333)
28	Adjust W. Asheville Vanderbilt 115kV Project	(383)
29	Adjust Asheville production displacement	(5,933)
30	Adjust coal inventory	(1,687)
31	Adjust EOL nuclear materials & supplies reserve expense	(1,813)
32	Adjust charitable contributions, corporate sponsorships, and corporate donations	(37)
33	Adjust lobbying expense	(1,544)
34	Adjust Board of Directors expense	(1,275)
35	Adjust inflation to December 31, 2019	2,012
36	Adjust nuclear decommissioning expense	(16,599)
37	Adjust to remove CertainTeed payment obligation	(4,958)
38	Adjust cash working capital under present rates	3,436
39	Adjust cash working capital under proposed rates	(6,001)
40	Rounding	3
41	Total revenue impact of Public Staff adjustments	(476,725)
42	**Public Staff recommended increase (decrease) in base rate revenue requirement**	**$ 109,236** 4/
43	Public Staff recommended increase (decrease) in base rate revenue requirement (L42)	$ 109,236
44	Annual Federal provisional EDIT Rider recommended by Public Staff for one year period	(113,983) 3/
45	Annual State EDIT Rider recommended by Public Staff for one year period	(24,516) 3/
46	Annual Federal unprotected EDIT Rider recommended by Public Staff for five year period	(94,146) 3/
47	Regulatory asset/liability rider for one year period recommended	(2,091) 5/
48	Public Staff recommended change in revenue requirement for first year (Sum of L43 through L47)	$ (125,500)
49	Public Staff recommended change in revenue requirement for years 2 through 5 (L43 + L46)	$ 15 090

1/ Smith Exhibit 1, Page 2, Line 8 (Prior to Company's rider-related revenue adjustment).

2/ Calculated based on Dorgan Exhibit 1, Schedules 2, 3, 4, 5, and backup schedules.

3/ The Public Staff is recommending that the Company's EDIT regulatory liabilities be refunded through one and five year riders. As a result, the Public Staff has removed the amounts included by the Company in its revenue requirement calculations associated with EDIT refunds, and instead has calculated separate riders that will credit customers for EDIT refunds over the corresponding periods. The calculation of all annual EDIT riders is shown on Dorgan Exhibit 2.

4/ Dorgan Exhibit 1, Schedule 5, Line 5.

5/ Smith Exhibit 5.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUPPORT FOR RECONCILIATION SCHEDULE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 1-1

Line No.	Item	Rate Base Impact 1/	Income Statement Impact 2/	Total Revenue Impact 3/
		(a)	(b)	(c)
1	Update plant and accumulated depreciation to December 31, 2019	($31,713)	($12,085)	($43,798)
2	Adjust unprotected EDIT for refund as a series of riders	42,907	-	42,907
3	Adjust for flowback of Protected EDIT	1,931	(31,760)	(29,829)
4	Adjust for severance costs	(1,233)	(5,169)	(6,402)
5	Adjust depreciation rates	3,466	(43,803)	(40,337)
6	Adjust for cost of service reallocations - SWP&A	(6,389)	(9,878)	(16,267)
7	Adjust deferred environmental costs	(23,825)	(88,040)	(111,865)
8	Adjust deferred non-ARO environmental costs	290	(4,077)	(3,787)
9	Adjust Asheville CC Plant in Service costs	(1,527)	(3,932)	(5,459)
10	Adjust Asheville CC deferral	-	(5,333)	(5,333)
11	Remove Storm Deferral	(39,462)	(44,689)	(84,151)
12	Adjust rate case expense	(212)	(348)	(560)

1/ Dorgan Exhibit 1, Schedule 2-1, Line 15.
2/ Dorgan Exhibit 1, Schedule 3-1, Line 18.
3/ Column (a) plus Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF GROSS REVENUE EFFECT FACTORS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 1-2

Line No.	Item		Capital Structure		Cost Rates		Retention Factor		Gross Revenue Effect	
			(a)		(b)		(c)		(d)	
1	**Rate Base Factor**									
2	Long-term debt		50.000%	1/	4.110%	1/	0.9963091	2/	0.0206261	4/
3	Common equity		50.000%	1/	9.00%	1/	0.7654709	3/	0.0587873	4/
4	Total (Sum of Lines 2 and 3)		100.000%						0.0794134	
									Amount	
5	**Net Income Factor**									
6	Total revenue								1.0000000	
7	Uncollectibles								0.0023940	5/
8	Balance (L6 - L7)								0.9976060	
9	Regulatory fee (L8 x 0.130%)	6/							0.0012969	
10	Balance (L8 - L9)								0.9963091	
11	State income tax (L10 x 2.7460%)	7/							0.0273586	
12	Balance (L10 - L11)								0.9689505	
13	Federal income tax (L12 x 21%)	8/							0.2034796	
14	Retention factor (L12 - L13)								0.7654709	

1/ Per Public Staff witness Woolridge.
2/ Line 10.
3/ Line 14.
4/ Column (a) multiplied by Column (b), divided by Column (c).
5/ NCUC Form E-1, Item No. 10, NC-0105, Line 3.
6/ Current NCUC regulatory fee rate effective.
7/ Dorgan Exhibit 1, Schedule 1-3, Line 4, Column (a).
8/ Statutory rate.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF WEIGHTED STATE INCOME TAX RATE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 1-3

Line No.	Item	Total System		North Carolina		South Carolina	
		(a)		(b)		(c)	
1	**Weighted state income tax rate**						
2	Apportionment factor			84.6380%	2/	12.6000%	2/
3	State income tax rate			2.50%	3/	5.00%	3/
4	Weighted state income tax rate	2.7460%	1/	2.11595%	4/	0.63000%	4/
5	**Composite income tax rate**						
6	Weighted state income tax rate (L4)	2.7460%					
7	Federal income tax rate	21%	5/				
8	Composite income tax rate	23.1693%	6/				

1/ Sum of Columns (b) and (c).
2/ NCUC Form E-1, Item No. 10, NC-0104, Column (b), Lines 3 and 4.
3/ NCUC Form E-1, Item No. 10, NC-0104, Column (a), Lines 3 and 4.
4/ Line 2 times Line 3.
5/ Statutory rate.
6/ 1 minus ((1 minus Line 6) multiplied by (1 minus Line 7)).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ORIGINAL COST RATE BASE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2

Line No.	Item	Under Present Rates: NC Retail Adjusted Per Company 1/	Under Present Rates: Public Staff Adjustments 2/	Under Present Rates: After Public Staff Adjustments 3/	After Public Staff Recommended Increase: Rate Increase	After Public Staff Recommended Increase: After Rate Increase 5/
		(a)	(b)	(c)	(d)	(e)
1	Electric plant in service	$19,386,469	($596,272)	$18,790,197	$0	$18,790,197
2	Accumulated depreciation and amortization	(8,144,508)	132,624	(8,011,884)	-	(8,011,884)
3	Net electric plant in service (L1 + L2)	$11,241,961	($463,648)	$10,778,313	$0	$10,778,313
4	Materials and supplies	603,695	(25,486)	578,209	-	578,209
	Other Working Capital					
5	Operating funds per lead-lag study	133,128	33,352	166,480	$9,611 4/	176,091
6	Unamortized debt	32,019	-	32,019	-	32,019
7	Regulatory assets and liabilities	481,429	(1,195,250)	(713,821)	-	(713,821)
8	Other	(13,453)	-	(13,453)	-	(13,453)
9	Total other working capital (Sum of L5 through L8)	633,123	(1,161,897)	(528,774)	9,611	(519,163)
10	ARO-related CCR regulatory assets and liabilities	-	142,237	142,237	-	142,237
11	Customer deposits	(116,588)	-	(116,588)	-	(116,588)
12	Accumulated deferred income taxes	(1,521,912)	799,185	(722,727)	-	(722,727)
13	Adjustments to federal excess deferred income taxes	-	24,311	24,311	-	24,311
14	Operating reserves	(54,705)	257	(54,448)	-	(54,448)
15	Construction work in progress	-	-	-	-	-
16	Total original cost rate base (L3 + L4 + L9 + sum of L10 through L15)	$10,785,574	($685,042)	$10,100,532	$9,611	$10,110,143

1/ Based on Smith Exhibit 1.
2/ Dorgan Exhibit 1, Schedule 2-1, Column (q).
3/ Column (a) plus Column (b).
4/ Dorgan Exhibit 1, Schedule 2-1(g), Line 80, Column (k).
5/ Column (c) plus Column (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1
Page 1 of 3

Line No.	Item		Update Plant and Accumulated Depreciation to 12/31/2019 2/	Remove EDIT Refund for Treatment as a Rider 3/	Include Flowback of Protected EDIT due to Tax Cuts & Jobs Act 4/	Adjust Depreciation Rates 5/	Adjust Severance Costs 6/	Adjust Storm Deferral 7/	Adjust Coal Inventory 8/
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Electric plant in service		($429,549)	$0	$0	$0	$0	($18,133)	$0
2	Accumulated depreciation and amortization		30,210	-	-	43,642	-	9	-
3	Net electric plant in service (L1 + L2)		($399,339)	$0	$0	$43,642	$0	($18,124)	$0
4	Materials and supplies		-	-	-	-	-	-	(21,244)
	<u>Other Working Capital</u>								
5	Operating funds per lead-lag study		-	-	-	-	-	-	-
6	Unamortized debt		-	-	-	-	-	-	-
7	Regulatory assets and liabilities		-	-	-	-	(20,206)	(623,180)	-
8	Other		-	-	-	-	-	-	-
9	Total Working Capital		-	-	-	-	(20,206)	(623,180)	-
10	ARO-related CCR regulatory assets and liabilities		-	-	-	-	-	-	-
11	Customer deposits		-	-	-	-	-	-	-
12	Accumulated deferred income taxes		-	540,295	-	-	4,682	144,387	-
13	Adjustments to federal excess deferred income taxes		-	-	24,311	-	-	-	-
14	Operating reserves		-	-	-	-	-	-	-
15	Construction work in progress		-	-	-	-	-	-	-
16	Total original cost rate base (L3 + L4 + L9 + sum of L10 through L15)		($399 339)	$540 295	$24 311	$43 642	($15 524)	($496 917)	($21 244)
17	Revenue requirement impact	1/	($31,713)	$42,907	$1,931	$3,466	($1,233)	($39,462)	($1,687)

1/ Line 14 times rate base retention factor of 0 0794134 from Dorgan Exhibit 1, Schedule 1-2.
2/ Dorgan Exhibit 1, Schedule 2-1(a).
3/ Dorgan Exhibit 1, Schedule 2-1(b).
4/ Dorgan Exhibit 1, Schedule 3-1(d).
5/ Dorgan Exhibit 1, Schedule 3-1(e).
6/ Dorgan Exhibit 1, Schedule 3-1(h).
7/ Dorgan Exhibit 1, Schedule 3-1(m).
8/ Dorgan Exhibit 1, Schedule 2-1(d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1
Page 2 of 3

Line No.	Item		Adjustment to Reclassify CCR Reg. Assets & Liabilities 9/	Adjustment to Deferred Non-ARO Enviromental Costs 9/	Adjustment to Remove Deferred Environmental Costs - ARO 9/	Adjustment to Remove Rate Case Expense 10/	Adjustment to COSS - SWP&A Reallocation 11/	Adjust Asheville CC Plant in Service Costs 12/	Adjust Asheville CC Deferral
			(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Electric plant in service		$ -	$ -	$ -	$ -	($143,764)	$ -	$ -
2	Accumulated depreciation and amortization		-	-	-	-	58,763	-	-
3	Net electric plant in service (L1 + L2)		$0	$0	$0	$0	($85,001)	$0	$0
4	Materials and supplies		-	-	-	-	(3,379)	(862)	-
	Other Working Capital								
5	Operating funds per lead-lag study		-	-	-	(2,670)	(7,240)	-	-
6	Unamortized debt		-	-	-	-	-	-	-
7	Regulatory assets and liabilities		(532,722)	4,758	-	-	-	(23,899)	-
8	Other		-	-	-	-	-	-	-
9	Total Working Capital		(532,722)	4,758	-	(2,670)	(7,240)	(23,899)	-
10	ARO-related CCR regulatory assets and liabilities		532,722	-	(390,485)	-	-	-	-
11	Customer deposits		-	-	-	-	-	-	-
12	Accumulated deferred income taxes		-	(1,102)	90,473	-	14,913	5,537	-
13	Adjustments to federal excess deferred income taxes		-	-	-	-	-	-	-
14	Operating reserves		-	-	-	-	257	-	-
15	Construction work in progress		-	-	-	-	-	-	-
16	Total original cost rate base (L3 + L4 + L9 + sum of L10 through L15)		$0	$3 655	($300 012)	($2 670)	($80 450)	($19 224)	$0
17	Revenue requirement impact	1/	$0	$290	($23,825)	($212)	($6,389)	($1,527)	$0

9/ Based on recommendation of Public Staff witness Maness.
10/ Dorgan Exhibit 1, Schedule 3-1(r).
11/ Dorgan Exhibit 1, Schedule 2-1(e).
12/ Dorgan Exhibit 1, Schedule 3-1(t).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1
Page 3 of 3

Line No.	Item		Adjust W. Asheville Vanderbilt 115kV Project 13/	Adjust Cash Working Capital 14/	Total Rate Base Adjustments 15/
			(o)	(p)	(q)
1	Electric plant in service		($4,826)	$0	($596,272)
2	Accumulated depreciation and amortization		-	-	132,624
3	Net electric plant in service (L1 + L2)		($4,826)	$0	($463,648)
4	Materials and supplies		-	-	(25,486)
	Other Working Capital				
5	Operating funds per lead-lag study		-	43,262	33,352
6	Unamortized debt		-	-	-
7	Regulatory assets and liabilities		-	-	(1,195,250)
8	Other		-	-	-
9	Total Working Capital		-	43,262	(1,161,897)
10	ARO-related CCR regulatory assets and liabilities		-	-	142,237
11	Customer deposits		-	-	-
12	Accumulated deferred income taxes		-	-	799,185
13	Adjustments to federal excess deferred income taxes		-	-	24,311
14	Operating reserves		-	-	257
15	Construction work in progress		-	-	-
16	Total original cost rate base (L3 + L4 + L9 + sum of L10 through L15)		($4 826)	$43 262	($685 042)
17	Revenue requirement impact	1/	($383)	$3,436	($54,401)

13/ Dorgan Exhibit 1, Schedule 2-1(c).
14/ Dorgan Exhibit 1, Schedule 2-1(f), Line 83
15/ Sum of Columns (a) through Column (p).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO UPDATE PLANT AND ACCUMULATED DEPRECIATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1(a)

Line No.	Item	Plant in Service (a)		Accumulated Depreciation (b)	
1	Adjustment to update balances to 12/31/2019	($429,549)	1/	$18,443	2/
2	Adjustment for annualization of depreciation expense	0		11,767	3/
3	Total adjustment to update plant and accumulated depreciation (L1 + L2)	($429,549)		$30,210	

1/ Dorgan Exhibit 1, Schedule 2-1(a)(1), Line 14, Column (g).
2/ Dorgan Exhibit 1, Schedule 2-1(a)(2), Line 12, Column (e).
3/ Dorgan Exhibit 1, Schedule 3-1(a), negative of Line 4.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO UPDATE PLANT IN SERVICE TO DECEMBER 31, 2019
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1(a)(1)

		Total System				
Line No.	Item	Amount As Of 12/31/2018 1/	Amount As Of 12/31/2019 2/	Change in Plant in Service 3/	NC Retail Percentage 4/	NC Retail Amount
		(a)	(b)	(c)	(f)	(g)
1	Steam plant	$3,892,843	$4,187,423	$294,580		
2	Hydro plant	143,939	153,412	9,473		
3	Other production plant	3,136,771	3,667,888	531,117		
4	Nuclear plant	8,124,103	8,462,915	338,812		
5	Acquisition adjustment		-	-		
6	Total production plant	15,297,656	16,471,638	1,173,982	60.8591%	$714,475 5/
7	Transmission plant	2,746,389	2,972,314	225,925	58.8448%	132,945 5/
8	Distribution plant	6,779,513	7,301,725	522,212	87.1486%	455,100 5/
9	General plant	611,462	657,447	45,985	73.7686%	33,923 5/
10	Intangible plant	494,528	595,217	100,689	67.3953%	67,860 5/
11	Total plant in service	$25,929,548	$27,998,342	$2,068,794		$1,404,303
12	Update to plant per Public Staff (L11)					$1,404,303
13	Less: Additional plant recovered in riders					0
14	Update to plant per Public Staff (L12 - L13)					$1,404,303
15	Company Adjustment					1,833,852 6/
16	Public Staff adjustment to update plant (L14 - L15)					($429,549)

1/ NCUC Form E-1, Item 10, NC-1008, Column (a).
2/ Based on Company response to Public Staff Data Request No. 1-7, updated to December 2019.
3/ Column (b) minus Column (a).
4/ NCUC Form E-1, Item No. 45B.
5/ Column (e) times Column (f).
6/ NCUC Form E-1, NC -1001, Item No. 10, Total NC Retail column, Line 23, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO UPDATE ACCUMULATED DEPRECIATION TO DECEMBER 31, 2019
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1(a)(2)

Line No.	Item	Total System: Amount As Of 12/31/2019 1/	Total System: Amount As Of 12/31/2018 2/	Total System: Change in Accumulated Depreciation 3/	NC Retail Percentage 4/	NC Retail Amount
		(a)	(b)	(c)	(d)	(e)
1	Production plant	($7,737,209)	($7,313,324)	($423,885)	60.8591%	($257,973) 5/
2	Transmission plant	(843,086)	(816,299)	(26,787)	58.8448%	(15,763) 5/
3	Distribution plant	(3,275,062)	(3,279,268)	4,206	87.1486%	3,665 5/
4	General plant	(190,421)	(172,426)	(17,995)	73.7686%	(13,275) 5/
5	Intangible plant	(406,548)	(355,262)	(51,286)	67.3953%	(34,564) 5/
6	Total accumulated depreciation	($12,452,326)	($11,936,579)	($515,747)		($317,910)
7	Change in accumulated depreciation (L6)					($317,910)
8	Less: Non-fuel rider activity					0
9	Public Staff adjustment to update through 12/31/2019					($317,910)
10	Company Adjustment					(336,353) 6/
11	Public Staff adjustment (L10 - L11)					$18,443

1/ Based on Company response to Public Staff Data Request No. 1-7, updated to December 2019.
2/ NCUC Form E-1, Item No. 10, NC -1009.
3/ Column (a) minus Column (b).
4/ NCUC Form E-1, Item No. 45B
5/ Column (c) times Column (d).
6/ NCUC Form E-1, Item No. 10, NC-1001, Line 34, Total NC Retail Column, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO ACCUMULATED DEPRECIATION
FOR ANNUALIZATION OF DEPRECIATION EXPENSE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1(a)(3)

Line No.	Item	Annualized Depreciation Expense at 12/31/2019 1/	Per Books Depreciation Expense for Twelve Months Ended 12/31/2019 1/	Difference 2/	NC Retail Percentage 3/	NC Retail Amount
		(a)	(b)	(c)	(d)	(e)
1	Production plant	$580,918	$535,850	$45,068	60.8591%	$27,428 4/
2	Transmission plant	55,084	51,796	3,288	58.8448%	1,935 4/
3	Distribution plant	181,489	173,119	8,370	87.1486%	7,294 4/
4	General plant	21,674	27,748	(6,074)	73.7686%	(4,481) 4/
5	Intangible plant	52,302	52,302	-	67.3953%	- 4/
6	Total accumulated depreciation	$891,466	$840,815	$50,651		$32,176
7	Adjustment to accumulated depreciation (-L7)					($32,176)
8	Company Adjustment					(43,943) 5/
9	Public Staff adjustment to accumulated depreciation					$11,767

1/ Based on information provided by Company.
2/ Column (a) minus Column (b).
3/ NCUC Form E-1, Item No. 45B
4/ Column (c) multiplied by Column (d).
5/ NCUC Form E-1, Item No. 10, NC-1001, Line 35, NC Retail Column, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO RATE BASE FOR TREATMENT AS A RIDER
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1(b)

Line No.	Item	Amount	
1	Adjustments required to flow back refunds to customers through a Rider:		
2	Adjustment to remove federal unprotected EDIT from rate base	($406,254)	1/
3	Adjustment to remove N.C. state EDIT from rate base	(23,726)	2/
4	Adjustment to remove over collection of revenues due to FIT rate change from rate base	(110,315)	3/
5	Public Staff Adjustments to rate base for tax changes (Sum of Lines 2 through 4)	($540,295)	

1/ Smith Exhibit 4, Line 8, Columns (b) and (c).
2/ Smith Exhibit 4, Line 8, Columns (d).
3/ Smith Exhibit 4, Line 8, Column (e).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO VANDERBILT - W. ASHEVILLE VANDERBILT 115KV PROJECT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1(c)

Line No.	Item	Amount	
1	W. Asheville - Vanderbilt 115kV Project Allocated at 100% to NC Retail per Company	$11,727	1/
2	W. Asheville - Vanderbilt 115kV Project Allocated at Transmission Level per Public Staff	6,901	2/
3	Total Public Staff adjustment to W. Asheville - Vanderbilt 115kV Project (L2 - L1)	($4,826)	

1/ Based on information provided by Company.
2/ Line 1 times SWPA NC Retail Allocation factor for Transmission Plant (DT) of 58.8448%.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO COAL INVENTORY
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1(d)

Line No.	Item	Total System		NC Retail Allocation		Total NC Retail	
1	Estimated full load burn - excluding retirements, in tons	32,017	1/				
2	Target number of days inventory	35	1/				
3	Target coal inventory balance at December 31, 2018 (L1 x L2)	1,120,595					
4	Projected average delivered coal cost per ton	$ 65.43	2/				
5	Projected coal inventory balance at target (L3 x L4/1,000)	$ 73,321		61.1093%	3/	$44,806	
6	Adjust for Fixed Transportation Costs	13,977	4/	61.1093%	3/	8,541	
7	Total coal inventory balance at target	$ 87,298				$ 53,347	
8	Actual coal inventory balance per Company	106,285	5/	61.1093%	3/	64,950	
9	Impact to materials and supplies (L7 - L8)	(18,987)				(11,603)	
10	Company Adjustment					9,641	6/
11	Adjustment to coal inventory (L9 - L10)					($21,244)	

1/ NCUC Form E-1, Item 46E, Coal Consumption and Inventory Data.
2/ Based on recommendation of Public Staff witness Metz.
3/ NCUC Form E-1, Item No. 45B, SWP&A Allocation Factor: E1.
4/ Per Public Staff witness Metz, the average delivered cost/ton does not include fixed transportation costs. The delivered cost of fuel used here is consistent with Docket No E-2, Sub 1204 with a projected period of 12/1/2019-11/30/2020.
=Target inventory balance in tons/estimated coal delivered in tons * Transportation Cost
5/ NCUC Form E-1, Item 10, NC-2401, Line 10.
6/ NCUC Form E-1, Item No. 10, NC-2401, Line 12, N.C. Retail Column, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ORIGINAL COST RATE BASE, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2-1(e)

		North Carolina Retail Operations		
Line No.	Item	SWP&A Company Rate Base Reallocated By Public Staff 1/	Summer CP Company Rate Base - Company Allocations 2/	Public Staff Adjustment: SWP&A Reallocation 3/
		(a)	(b)	(c)
1	Electric plant in service	$19,242,705	$19,386,469	($143,764)
2	Accumulated depreciation and amortization	(8,085,745)	(8,144,508)	58,763
3	Net electric plant in service (L1 + L2)	$11,156,960	$11,241,961	($85,001)
4	Materials and supplies	600,316	603,695	(3,379)
5	Working capital investment	509,295	516,535	(7,240)
6	Accumulated deferred taxes	(1,506,999)	(1,521,912)	14,913
7	Operating reserves	(54,448)	(54,705)	257
8	Construction work in progress	(0)	(0)	-
9	Total Original Cost Rate Base (Sum of L3 through L8)	$10,705,124	$10,785,574	($80,450)

1/ Dorgan Exhibit III, Schedule 1, Column (c).
2/ Dorgan Exhibit I, Schedule 2, Column (a).
3/ Column (a) - Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E 2, Sub 1219
North Carolina Retail Operations

Public Staff
Dorgan Exhibit 1
Schedule 2 1(f)

CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY UNDER PRESENT RATES

For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Line No.	Item	Per Books Amounts 1/	Company Ratemaking Adjustments 2/	After Company Adjustments 3/	Public Staff Adjustments /	After Public Staff Adjustments 5/	Lead / Lag Days 6/	Working Cap tal From Lead/ Lag Study 7/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Electric operating revenues							
2	Rate revenues	$3,575,788	($318,129)	$3,257,659	$3,929	$3,261,588	41.88	$374,234
3	Sales for resale revenues	134,915	-	134,915	-	134,915	33.73	12,468
4	Provisions for rate refunds	(104,546)	-	(104,546)	-	(104,546)	41.88	(11,996)
5	Forfe ted discounts	7,664	-	7,664	-	7,664	72.30	1,518
6	Miscellaneous service revenues	5,506	-	5,506	-	5,506	76.00	1,146
7	Rent revenues - production plant related	4,466	-	4,466	-	4,466	41.63	509
8	Rent revenues - distribution pole rental revenue	10,901	-	10,901	-	10,901	182.00	5,436
9	Rent revenues - transmission plant related	382	-	382	-	382	41.63	44
10	Rent revenues - additional fac lities - wholesale	-	-	-	-	-	-	-
11	Rent revenues - additional fac lities - ret X lighting	4,617	-	4,617	-	4,617	41.63	527
12	Rent revenues - additional fac lities - lighting	3,849	-	3,849	-	3,849	41.63	439
13	Rent revenues - other	3,413	-	3,413	-	3,413	68.21	638
14	Other revenues - production plant related	1,184	-	1,184	-	1,184	41.88	136
15	Other revenues - transmission related	6,208	-	6,208	-	6,208	41.88	712
16	Other revenues - wholesale D/A	368	-	368	-	368	41.88	42
17	Other revenues - REPS	1,114	-	1,114	-	1,114	41.88	128
18	Other revenues - other energy	-	-	-	-	-	-	-
19	Other revenues - distribution plant related	1,404	-	1,404	-	1,404	41.88	161
20	Other revenues - NC retail specific	271	-	271	-	271	41.88	31
21	Electric operating revenues	3 657 503	(318 129)	3 339 374	3 929	3 343 303	42.16	386 173
22	Fuel used in electric generation							
23	O&M production energy - fuel	863,120	(46,419)	816,701	(1,598)	815,104	28.49	63,623
24	RECS consumption expense	18 522	-	18 522	-	18 522	28.49	1 446
25	Fuel used in electric generation	881 642	(46 419)	835 223	(1 598)	833 625	28.49	65 069
26	Purchased power							
27	O&M production purchases - capac ty cost	67,280	-	67,280	-	67,280	30.29	5,583
28	O&M production purchases - energy cost	365,384	(1,965)	363,419	(710)	362,709	30.29	30,100
29	O&M deferred fuel expense	(273 901)	-	(273 901)	-	(273 901)	28.49	(21 379)
30	Purchased power	158,763	(1,965)	156,798	(710)	156,088	33.45	14,304
31	Other O&M expense							
32	Labor expense	430,295	(20,911)	409,384	(14,358)	395,026	37.07	40,119
33	Pension & benef ts	76,271	(3,060)	73,211	-	73,211	13.97	2,802
34	Regulatory commission expense	7,038	(234)	6,804	-	6,804	93.25	1,738
35	Property insurance	(526)	-	(526)	-	(526)	(222.30)	320
36	Injuries & damages - workman's compensation	197	-	197	-	197	-	-
37	Unco lectible accounts	8,937	-	8,937	-	8,937	-	-
38	Other O&M expense	528,607	4,722	533,329	(32,448)	500,881	40.52	55,605
39	Adjust for other revenue		(1,105)	(1,105)	-	(1,105)	35.19	(107)
40	Adjust for non fuel riders/aviation/merger		(141,603)	(141,603)	-	(141,603)	35.19	(13,652)
41	Adjust for non-labor O&M		1,311	1,311	-	1,311	32.27	116
42	Adjust for rate case expense/reg assets & liabilities		2,304	2,304	-	2,304	-	-
43	Adjust for Severance		(23,366)	(23,366)	-	(23,366)	31.67	(2,027)
44	Adjust for Outside Services		-	-	(146)	(146)	31.67	(13)
45	Adjust for Asheville and CertainTeed		4,635	4,635	-	4,635	35.19	447
46	Other adjustments to regulatory fees and uncollect bles			-	-	-	-	-
47	Total Other O&M expenses	1,050,819	(177,307)	873,512	(46,952)	826,560	37.69	85,348
48	Depreciation | amortization | P&C losses							
49	Depreciation & amortization	669,787	301,368	971,155	(203,970)	767,186	-	-
50	Adjust other amortization expense		-	-	(31 642)	(31 642)	-	-
51	Total depreciation & amortization expense	669,787	301,368	971,155	(235,612)	735,544	-	-
52	Taxes other than income taxes							
53	Payroll taxes	26,288	(1,155)	25,133	109	25,242	48.41	3,348
54	Property taxes	68,133	10,664	78,797	-	78,797	186.50	40,262
55	Other taxes - federal heavy vehicle use tax	48	-	48	(1,713)	(1,665)	-	-
56	Other taxes - electric excise tax - SC	-	-	-	-	-	-	-
57	Other taxes - privilege tax	12,244	-	12,244	-	12,244	(11.97)	(402)
58	Miscellaneous taxes - NC	(4,517)	-	(4,517)	(701)	(5,218)	60.00	(858)
59	Miscellaneous taxes - SC & other states	1	-	1	-	1	129.46	-
60	Other taxes - PUC license tax - SC	-	-	-	-	-	-	-
61	Adjust costs recovered through non-fuel riders		(6,458)	(6,458)	-	(6,458)	124.03	(2,194)
62	Adjust to reflect retirement of Asheville Steam Generating Plant		(1 032)	(1 032)	-	(1 032)	186.50	(527)
63	Total taxes other than income taxes	102,197	2,019	104,216	(2,305)	101,911	141.93	39,629
64	Interest on customer deposits	7,971	-	7,971	-	7,971	137.50	3,003
65	Income taxes							
66	Federal income taxes	(49,091)	49,091	-	-	-	44.75	-
67	State income taxes	(2,917)	2,917	-	-	-	44.75	-
68	Income taxes - deferred	164,994	(164,994)	(0)	-	(0)	-	-
69	Adjust for Federal income taxes | Adjust NC income taxes for			-				-
70	rate change | Synchronize interest expense		(138,188)	(138,188)	-	(138,188)	20.60	(7,799)
71	Adjust costs recovered through non-fuel riders		63,161	63,161	-	63,161	-	-
72	Adjust for Federal & State income taxes		112,986	112,986	68,256	181,242	20.60	10,229
73	Total income taxes	112 986	(75 027)	37 959	68 256	106 214	8.35	2 430
74	Amortization of ITC	(2,134)	(1,481)	(3,615)	34	(3,581)	-	-
75	Total utility operating expenses	2,982,032	1,188	2,983,219	(218,887)	2,764,332	27.70	209,783
76	Interest expense	211,661	(530)	211,131	(3,960)	207,171	-	-
77	Income available for common equity	463,810	(318,787)	145,024	-	145,024	-	-
78	Net operating income for return	675,472	(319,317)	356,155	(3,960)	352,195	-	-
79	Total requirement	3 657 503	(318 129)	3 339 374	(222 847)	3 116 527	24.57	209 783
80	Cash working capital per Public Staff, before Sales Tax Adjustment (L21 - (L75 + L76))							176,390
81	Amount per Books per Company application						160,141 8/	
82	ADD(LESS) Accounting Adjustments						(27,013) 8/	133,128 8/
83	Adjustment to cash working capital							43,262

1/ NCUC Form E-1, Item No. 14, Lead Lag Summary Detail, NC Retail Jurisdictional Amount.
2/ Smith Exhibit 1.
3/ Column (a) plus Column (b).
4/ Dorgan Exhibit 1, Schedule 2-1(f)(1), Column (ad).
5/ Column (c) plus Column (d).
6/ NCUC Form E-1, Item No. 14, Lead Lag Summary Detail, as corrected by the Company.
7/ Column (e) divided by 365 days, multiplied by Column (f).
8/ Smith Exhibit 1, Page 4d, Line 1, Columns (2), (3), and (4)

DUKE ENERGY PROGRESS LLC
Docket No E 2 Sub 1219
Nor h Caro ina Reta l Operations
PUBLIC S AFF AD US MEN S O BE REFLEC ED IN
LEAD LAG CALCULA ION
For the est Year Ended December 31 2018
(Dollar Amounts Expressed in housands)

Publ c Staff
Dorgan Exhibit 1
Schedu e 2 1(f)(1)
Page 1 of 2

Line No.	Item	Update P ant to 12 31 2019	Update Revenues/ Customer Growth/ Weather to 12/31/2019	Adjust Cred t Card Fees	Remove EDIT Refunds for Treatment as Riders	Include F owback EDIT due to Tax Cuts & Jobs Act	Adjust Deprecia ion Rates	Adjust Salaries & Wages	Adjust Incen ives	Adjust Severance Cos s	Adjust Executive Compensation	Adjust Aviation Expenses	Adjust EOL Nuc ear M&S Rese ve Amort zation	Adjustment to Remove Deferred Environmental Costs - ARO	Adjustment to Remove De erred Non-ARO Enviromental Costs	Adjust to Normal ze Storm Costs	Adjust Storm Deferral	Adjust Lobbying Expense	Adjust Boa d of Directors Expense	Adjust Outside Serv ces
		(a)	(b)	c)	(d)	(e)	(f)	(g)	(h)	( )	(j)	(k)	( )	(m)	(n)	(o)	(p)	(q)	(r)	(s)
1	Electr c operating revenues:																			
2	Rate revenues	$0	$,09	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Sales for resale revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Provisions for rate refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	For ei ed discoun s	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	M sce laneous serv ce revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Rent revenues - product on plant elated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Rent revenues - distribution pole rental revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Rent revenues - t ansm ssion plant re ated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Rent revenues - add tional fac lit es - wholesale	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Rent revenues - add tional fac lit es - ret X ighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Rent revenues - add tional fac lit es - l gh ing	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Rent revenues - other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1	Other revenues - product on plant rela ed	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Other revenues - transm ssion related	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Other revenues - wholesale D/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Other revenues - REPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Other revenues - other energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Other revenues - d stribution p ant re ated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Other revenues - NC reta l speci ic	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Electr c operating revenues	-	,09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Fuel used in electric generation:																			
23	O&M produc ion energy - fuel	-	(1,598)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	RECS consumpt on expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Fuel used in electric generation	-	(1,598)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Purchased power:																			
27	O&M produc ion pu chases - capacity cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	O&M produc ion pu chases - energy cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	O&M deferred fuel expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Purchased power	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Other O&M expense:																			
32	Labor expense	-	-	-	-	-	-	1,932	(1 ,652)	-	(160)	-	-	-	-	-	-	($1, 78)	-	-
33	Pension & benef ts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Regula ory commission expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Property insurance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Injuries & damages - workman's compensa ion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Uncol ectib e accounts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Other O&M expense	-	(3,168)	(91)	-	-	-	-	-	(5,150)	-	(05)	-	-	-	9 300	-	(60)	($1,270)	-
39	Adjust for other revenue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0	Adjust for non fuel r ders/av at on/merger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1	Adjust for non-labor O&M	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Adjust for ate case expense/reg assets & iabil ties	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Adjust for Severance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Adjust for Outs de Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1 6)
5	Adjust for Ashevil e and CertainTeed	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other adjustments to regula ory fees and unco lectibles	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	To al Other O&M expenses	-	(3,168)	(91)	-	-	-	1,932	(1 ,652)	(5,150)	(160)	(05)	-	-	-	9 300	-	(1,538)	(1,270)	(1 6)
8	Deprec at on | amortizat on | P&C osses:																			
9	Deprec at on & amo tizat on	(10,328)	-	-	-	-	(3,6 2)	-	-	-	-	-	(1 807)	(87,715)	(,062)	-	(,52)	-	-	-
50	Adjust other amortizat on expense	-	-	-	-	(31,6 2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	To al deprecia ion & amortizat on expense	(10,328)	-	-	-	(31,6 2)	(3,6 2)	-	-	-	-	-	(1 807)	(87,715)	(,062)	-	(,52)	-	-	-
52	Taxes other than income taxes:																			
53	Payro l taxes	-	-	-	-	-	-	109	-	-	-	-	-	-	-	-	-	-	-	-
5	Property taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Other taxes - federal heavy veh c e use tax	(1,711)	-	-	-	-	-	-	-	-	-	(2)	-	-	-	-	-	-	-	-
56	Other taxes - electric excise ax - SC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	Other taxes - p ivilege tax	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	M sce laneous taxes - NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	M sce laneous taxes - SC & other sta es	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Other taxes - PUC icense ax - SC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Adjust costs recovered through non-fuel r ders	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
62	Adjust to reflect retirement of Ashevi le S eam Generating Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63	To al axes other than income taxes	(1,711)	-	-	-	-	-	109	-	-	-	(2)	-	-	-	-	-	-	-	-
6	Interest on customer deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Income axes:																			
66	Federal income taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
67	Sta e income taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Income axes - defe red	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Adjust for Federal income taxes | Adjust NC income taxes for																			
70	rate change | Synchronize interest expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71	Adjust costs recovered through non-fuel r ders	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Adjust for Federal & State income axes	2,789	2,053	21	-	7,331	10,112	(73)	3,395	1,193	37	9	19	20,323	9 1	(2,155)	10,316	356	29	3
73	To al income axes	2,789	2,053	21	-	7,331	10,112	(73)	3,395	1,193	37	9	19	20,323	9 1	(2,155)	10,316	356	29	3
7	Amort zation of ITC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	To al uti ity operating expenses	(9,250)	(2,713)	(70)	-	(2 ,311)	(33,530)	1,568	(11,257)	(3,957)	(123)	(313)	(1 388)	(67,392)	(3,121)	7,1 5	(3 ,208)	(1,182)	(976)	(112)
76	Interest expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77	Income avai ab e or common equ ty 2	9,250	6,807	70	-	2 ,311	33,530	(1,568)	11,257	3,957	123	313	1 388	67,392	3,121	(7,1 5)	3 ,208	1,182	976	112
78	Net operating income or return	9,250	6,807	70	-	2 ,311	33,530	(1,568)	11,257	3,957	123	313	1 388	67,392	3,121	(7,1 5)	3 ,208	1,182	976	112
79	To al equirement	-	,09	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

1/ Based on adjustments made by Pub ic Staff in Dorgan Exhib t 1, Schedule 3-1.
2/ Line 21 minus Line 75 minus Line 77.
3/ Sum of Columns (a) through Column (ad).

I/A

DUKE ENERGY PROGRESS LLC
Docket No E 2 Sub 1219
Nor h Caro ina Reta l Operations
PUBLIC S AFF AD US MEN S O BE REFLEC ED IN
LEAD LAG CALCULA ION
For the est Year Ended December 31 2018
(Dollar Amounts Expressed in housands)

Public Staff
Dorgan Exhibit 1
Schedule 2 1(f)(1)
Page 2 of 2

Line No.	Item	Adjust Charitable Contribu ions, and Corporate Sponsorships & Donations	Adjustment to Inflation Adjustment	Adjustment to Remove Ce tainTeed Payment Obl ga ion	Adjustment to Nuc ear Decommiss oning Expense	Adjustment to Remove Ra e Case Expense	Adjustment to COSS - SWP&A Reallocation	Adjust Ashevi le CC Plant in Serv ce Costs	Adjust Ashevil e CC Deferral	Adjust for Ashevil e Production Displacement	Interest Synchronizat on	Total Pub ic Staff Adjustments [3]
		(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	ab)	(ac)	(ad)
1	Electr c operating revenues:											
2	Rate revenues	$0	$0	$0	$0	$0	($165)	$0	$0	$0	$0	$3,929
3	Sales for resale revenues	-	-	-	-	-	-	-	-	-	-	-
	Provisions for rate refunds	-	-	-	-	-	-	-	-	-	-	-
5	For ei ed discoun s	-	-	-	-	-	-	-	-	-	-	-
6	M sce laneous serv ce revenues	-	-	-	-	-	-	-	-	-	-	-
7	Rent revenues - product on plant elated	-	-	-	-	-	-	-	-	-	-	-
8	Rent revenues - distribution pole rental revenue	-	-	-	-	-	-	-	-	-	-	-
9	Rent revenues - t ansm ssion plant re ated	-	-	-	-	-	-	-	-	-	-	-
10	Rent revenues - add tional fac lit es - wholesale	-	-	-	-	-	-	-	-	-	-	-
11	Rent revenues - add tional fac lit es - ret X ighting	-	-	-	-	-	-	-	-	-	-	-
12	Rent revenues - add tional fac lit es - l gh ing	-	-	-	-	-	-	-	-	-	-	-
13	Rent revenues - other	-	-	-	-	-	-	-	-	-	-	-
1	Other revenues - product on plant rela ed	-	-	-	-	-	-	-	-	-	-	-
15	Other revenues - transm ssion related	-	-	-	-	-	-	-	-	-	-	-
16	Other revenues - wholesale D/A	-	-	-	-	-	-	-	-	-	-	-
17	Other revenues - REPS	-	-	-	-	-	-	-	-	-	-	-
18	Other revenues - other energy	-	-	-	-	-	-	-	-	-	-	-
19	Other revenues - d stribution p ant re ated	-	-	-	-	-	-	-	-	-	-	-
20	Other revenues - NC reta l speci ic	-	-	-	-	-	-	-	-	-	-	-
21	Electr c operating revenues	-	-	-	-	-	(165)	-	$0	$0	-	$3,929
22	Fuel used in electric generation:											
23	O&M produc ion energy - fuel	-	-	-	-	-	-	-	-	-	-	(1,598)
2	RECS consumpt on expense	-	-	-	-	-	-	-	-	-	-	-
25	Fuel used in electric generation	-	-	-	-	-	-	-	-	-	-	(1,598)
26	Purchased power:											
27	O&M produc ion pu chases - capacity cost	-	-	-	-	-	-	-	-	-	-	-
28	O&M produc ion pu chases - energy cost	-	-	-	-	-	710)	-	-	-	-	(710)
29	O&M deferred fuel expense	-	-	-	-	-	-	-	-	-	-	-
30	Purchased power	-	-	-	-	-	710)	-	-	-	-	(710)
31	Other O&M expense:											
32	Labor expense	-	-	-	-	-	-	-	-	-	-	(1 ,358)
33	Pension & benef ts	-	-	-	-	-	-	-	-	-	-	-
3	Regula ory commission expense	-	-	-	-	-	-	-	-	-	-	-
35	Property insurance	-	-	-	-	-	-	-	-	-	-	-
36	Injuries & damages - workman's compensa ion	-	-	-	-	-	-	-	-	-	-	-
37	Uncol ectib e accounts	-	-	-	-	-	-	-	-	-	-	-
38	Other O&M expense	($36)	2,005	(,939)	(16,537)	(3 6)	(1 922)	(3,918)	-	(5 910)	-	(32, 8)
39	Adjust for other revenue	-	-	-	-	-	-	-	-	-	-	-
0	Adjust for non fuel r ders/av at on/merger	-	-	-	-	-	-	-	-	-	-	-
1	Adjust for non-labor O&M	-	-	-	-	-	-	-	-	-	-	-
2	Adjust for ate case expense/reg assets & iabil ties	-	-	-	-	-	-	-	-	-	-	-
3	Adjust for Severance	-	-	-	-	-	-	-	-	-	-	-
	Adjust for Outs de Services	-	-	-	-	-	-	-	-	-	-	(1 6)
5	Adjust for Ashevil e and CertainTeed	-	-	-	-	-	-	-	-	-	-	-
6	Other adjustments to regula ory fees and unco lectibles	-	-	-	-	-	-	-	-	-	-	-
7	To al Other O&M expenses	(36)	2,005	(,939)	(16,537)	(3 6)	(1 922)	(3,918)	-	(5 910)	-	(6,952)
8	Deprec at on | amortizat on | P&C osses:											
9	Deprec at on & amo tizat on	-	-	-	-	-	(6 579)	-	(5,313)	-	-	(203,970)
50	Adjust other amortizat on expense	-	-	-	-	-	-	-	-	-	-	(31,6 2)
51	To al deprecia ion & amortizat on expense	-	-	-	-	-	(6 579)	-	(5,313)	-	-	(235,612)
52	Taxes other than income taxes:											
53	Payro l taxes	-	-	-	-	-	-	-	-	-	-	109
5	Property taxes	-	-	-	-	-	-	-	-	-	-	-
55	Other taxes - federal heavy veh c e use tax	-	-	-	-	-	-	-	-	-	-	(1,713)
56	Other taxes - electric excise ax - SC	-	-	-	-	-	-	-	-	-	-	-
57	Other taxes - p ivilege tax	-	-	-	-	-	-	-	-	-	-	-
58	M sce laneous taxes - NC	-	-	-	-	-	701)	-	-	-	-	(701)
59	M sce laneous taxes - SC & other sta es	-	-	-	-	-	-	-	-	-	-	-
60	Other taxes - PUC icense ax - SC	-	-	-	-	-	-	-	-	-	-	-
61	Adjust costs recovered through non-fuel r ders	-	-	-	-	-	-	-	-	-	-	-
62	Adjust to reflect retirement of Ashevi le S eam Generating Plant	-	-	-	-	-	-	-	-	-	-	-
63	To al axes other than income taxes	-	-	-	-	-	701)	-	-	-	-	(2,305)
6	Interest on customer deposits	-	-	-	-	-	-	-	-	-	-	-
65	Income axes:											
66	Federal income taxes	-	-	-	-	-	-	-	-	-	-	-
67	Sta e income taxes	-	-	-	-	-	-	-	-	-	-	-
68	Income axes - defe red	-	-	-	-	-	-	-	-	-	-	-
69	Adjust for Federal income taxes | Adjust NC income taxes for											
70	rate change | Synchronize interest expense	-	-	-	-	-	-	-	-	-	-	-
71	Adjust costs recovered through non-fuel r ders	-	-	-	-	-	-	-	-	-	-	-
72	Adjust for Federal & State income axes	8	(65)	1,1	3,831	80	2,152	908	1,231	1 369	918	68,256
73	To al income axes	8	(65)	1,1	3,831	80	2,152	908	1,231	1 369	918	68,256
7	Amort zation of ITC	-	-	-	-	-	3	-	-	-	-	3
75	To al uti ity operating expenses	(28)	1,5 0	(3,795)	(12,706)	(266)	(7 726)	(3,010)	(,082)	(5 1)	918	(218,887)
76	Interest expense	-	-	-	-	-	-	-	-	-	(3,960)	(3,960)
77	Income avai ab e or common equ ty [2]	28	(1,5 0)	3,795	12,706	266	7 561	3,010	- ,082	5 1	3,0 3	226,776
78	Net operating income or return	28	(1,5 0)	3,795	12,706	266	7 561	3,010	- ,082	5 1	(918)	222,816
79	To al equirement	-	-	-	-	-	(165)	-	-	-	-	3,929

DUKE ENERGY PROGRESS, LLC
Docket No. E 2, Sub 1219
North Caro ina Retail Operations
CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY AFTER RATE INCREASE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2 1(g)
Page 1 of 2

Line No.	Item	Under Present Rates After Adjustments 1/	Lead Lag Days /	Iteration 1 Increase	Iteration 1 W th Increase 8/	Iteration 1 CWC Change 10/	Line No.
		(a)	(b)	(c)	(d)	(e)	
1	Electric operating revenues						1
2	Rate revenues	$3,261,588	41.88	$404,327 5/	$3,665,915	$46,392	2
3	Sales for resale revenues	134,915	33.73	-	134,915	-	3
4	Provisions for rate refunds	(104,546)	41.88	-	(104,546)	-	4
5	Forfeited discounts	7,664	72.30	-	7,664	-	5
6	Miscellaneous service revenues	5,506	76.00	-	5,506	-	6
7	Rent revenues - production plant related	4,466	41.63	-	4,466	-	7
8	Rent revenues - distribution pole rental revenue	10,901	182.00	-	10,901	-	8
9	Rent revenues - transmission plant related	382	41.63	-	382	-	9
10	Rent revenues - add tional facil ties - wholesale	-	-	-	-	-	10
11	Rent revenues - add tional facil ties - ret X lighting	4,617	41.63	-	4,617	-	11
12	Rent revenues - add tional facil ties - lighting	3,849	41.63	-	3,849	-	12
13	Rent revenues - other	3,413	68.21	-	3,413	-	13
14	Other revenues - production plant related	1,184	41.88	-	1,184	-	14
15	Other revenues - transmission related	6,208	41.88	-	6,208	-	15
16	Other revenues - wholesale D/A	368	41.88	-	368	-	16
17	Other revenues - REPS	1,114	41.88	-	1,114	-	17
18	Other revenues - other energy	-	-	-	-	-	18
19	Other revenues - distribution plant related	1,404	41.88	-	1,404	-	19
20	Other revenues - NC retail specific	271	41.88	-	271	-	20
21	Electric operating revenues	$3 343 303	42.16	404 327 6/	3 747 630	46 392	21
22	Fuel used in electric generation						22
23	O&M production energy - fuel	815,104	28.49	-	815,104	-	23
24	RECS consumption expense	18 522	28.49	-	18 522	-	24
25	Fuel used in electric generation	833 625	28.49	-	$833 625	-	25
26	Purchased power						26
27	O&M production purchases - capacity cost	67,280	30.29	-	67,280	-	27
28	O&M production purchases - energy cost	362,709	30.29	-	362,709	-	28
29	O&M deferred fuel expense	(273 901)	28.49	-	(273 901)	-	29
30	Purchased power	156 088	33.45	-	156 088	-	30
31	Other O&M expense						31
32	Labor expense	395,026	37.07	-	395,026	-	32
33	Pension & benefits	73,211	13.97	-	73,211	-	33
34	Regulatory commission expense	6,804	93.25	-	6,804	-	34
35	Property insurance	(526)	(222.30)	-	(526)	-	35
36	Injuries & damages - workman's compensation	197	-	-	197	-	36
37	Uncollectible accounts	8,937	-	-	8,937	-	37
38	Other O&M expense	500,881	40.52	-	500,881	-	38
39	Adjust for other revenue	(1,105)	35.19	-	(1,105)	-	39
40	Adjust for non fuel riders/aviation/merger	(141,603)	35.19	-	(141,603)	-	40
41	Adjust for non-labor O&M	1,311	32.27	-	1,311	-	41
42	Adjust for rate case expense/reg assets & liabilities	2,304	-	-	2,304	-	42
43	Adjust for Severance	(23,366)	31.67	-	(23,366)	-	43
44	Adjust for Outside Services	(146)	31.67	-	(146)	-	44
45	Adjust for Asheville and CertainTeed	4,635	35.19	-	4,635	-	45
46	Other adjustments to regulatory fees and unco lectibles			-	-	-	46
47	Total Other O&M expenses	826 560	37.69	-	826 560	-	47
48	Depreciation | amortization | P&C losses						48
49	Depreciation & amortization	767,186	-	-	767,186	-	49
50	Adjust other amortization expense	(31 642)	-	-	(31 642)	-	50
51	Total depreciation & amortization expense	735 544		-	735 544	-	51
52	Taxes other than income taxes						52
53	Payroll taxes	25,242	48.41	-	25,242	-	53
54	Property taxes	78,797	186.50	-	78,797	-	54
55	Other taxes - federal heavy vehicle use tax	(1,665)	-	-	(1,665)	-	55
56	Other taxes - electric excise tax - SC	-	-	-	-	-	56
57	Other taxes - priv lege tax	12,244	(11.97)	-	12,244	-	57
58	Miscellaneous taxes - NC	(5,218)	60.00	-	(5,218)	-	58
59	Miscellaneous taxes - SC & other states	1	129.46	-	1	-	59
60	Other taxes - PUC icense tax - SC	-	-	-	-	-	60
61	Adjust costs recovered through non-fuel riders	(6,458)	124.03	-	(6,458)	-	61
62	Adjust to reflect retirement of Ashevi le Steam Generating Plant	(1 032)	186.50	-	(1 032)	-	62
63	Total taxes other than income taxes	101 911	141.93	-	101 911	-	63
64	Interest on customer deposits	7 971	137.50	-	7 971	-	64
65	Income taxes						65
66	Federal income taxes	-	44.75	-	-	-	66
67	State income taxes	-	44.75	-	-	-	67
68	Income taxes - deferred	-	-	-	-	-	68
69	Adjust for Federal income taxes | Adjust NC income taxes for rate						69
70	change | Synchronize interest expense	(138,188)	20.60	-	(138,188)	-	70
71	Adjust costs recovered through non-fuel riders	63,161	-	-	63,161	-	71
72	Adjust for Federal & State income taxes	181 242	20.60	-	181 242	-	72
73	Total income taxes	106 215	8.35	-	106 215	-	73
74	Amortization of ITC	(3 581)	-	-	(3 581)	-	74
75	Total electric operating expenses	2 764 333		-	2 764 333	-	75
76	Interest expense	207,171	-	-	207,171	-	76
77	Income ava lable for common equ ty	145 024	-	309 500 7/	454 524 9/	-	77
78	Net operating income for return	352 195		309 500	661 695	-	78
79	Total requirement	$3 116 527		$309 500	$3 426 028	$0	79
80	Cumulative change in working capital					$46,392	80
81	Rate base under present rates					10 100 532	81
82	Rate base after rate increase	$10 100 532 2/				$10 146 924	82
83	Overall rate of return (L78 / L82)	3.49%				6.52%	83
84	Target rate of return	6.56% 3/				6.56% 3/	84

1/ Dorgan Exhibit 1, Schedule 2-1(f), Column (e).
2/ Dorgan Exhibit 1, Schedule 2, Line 16, Column (c).
3/ Dorgan Exhibit 1, Schedule 4, Line 3, Column (h).
4/ Dorgan Exhibit 1, Schedule 2-1(f), Column (f).
5/ Line 21 minus (Sum of Line 3 through Line 20).
6/ Line 77 divided by equity retention factor of 0.7654709 from Dorgan Exhib t 1, Schedule 1-2, Line 14.
7/ Column (d) minus Column (a).
8/ Column (a) plus Column (c), unless footnoted otherwise..
9/ Line 82, Column (a) mu tiplied by 50.000% multiplied by 9.000%.
10/ Column (c) divided by 365 days multip ied by Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E 2, Sub 1219
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY AFTER RATE INCREASE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 2 1(g)
Page 2 of 2

Item	Iteration 2 Increase	Iteration 2 With Increase 12/	Iteration 2 CWC Change 16/	Iteration 3 Increase	Iteration 3 With Increase 19/	Iteration 3 CWC Change 23/	After Increase Cumulative Increase 2 /	After Increase After Increase 25/
	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Electric operating revenues								
Rate revenues	(318,166) 5/	$3,347,748	($36,506)	($2,393) 5/	$3,345,355	($275)	$83,767	$3,345,355
Sales for resale revenues	-	134,915	-	-	134,915	-	-	134,915
Provisions for rate refunds	-	(104,546)	-	-	(104,546)	-	-	(104,546)
Forfeited discounts	-	7,664	-	-	7,664	-	-	7,664
Miscellaneous service revenues	-	5,506	-	-	5,506	-	-	5,506
Rent revenues - production plant related	-	4,466	-	-	4,466	-	-	4,466
Rent revenues - distr bution pole rental revenue	-	10,901	-	-	10,901	-	-	10,901
Rent revenues - transmission plant related	-	382	-	-	382	-	-	382
Rent revenues - additional facilities - wholesale	-	-	-	-	-	-	-	-
Rent revenues - additional facilities - ret X lighting	-	4,617	-	-	4,617	-	-	4,617
Rent revenues - additional facilities - ighting	-	3,849	-	-	3,849	-	-	3,849
Rent revenues - other	-	3,413	-	-	3,413	-	-	3,413
Other revenues - production plant related	-	1,184	-	-	1,184	-	-	1,184
Other revenues - transmission related	-	6,208	-	-	6,208	-	-	6,208
Other revenues - wholesale D/A	-	368	-	-	368	-	-	368
Other revenues - REPS	-	1,114	-	-	1,114	-	-	1,114
Other revenues - other energy	-	-	-	-	-	-	-	-
Other revenues - distribution plant related	-	1,404	-	-	1,404	-	-	1,404
Other revenues - NC reta l specific	-	271	-	-	271	-	-	271
Electric operating revenues	(318 166) 11/	3 429 464 13/	(36 506)	(2 393) 17/	3 427 071 20/	(275)	83 767	$3 427 071
Fuel used in electric generation								
O&M production energy - fuel	-	815,104	-	-	815,104	-	-	815,104
RECS consumption expense	-	18 522	-	-	18 522	-	-	18 522
Fuel used in electric generation	-	833 625	-	-	833 625	-	-	833 625
Purchased power								
O&M production purchases - capacity cost	-	67,280	-	-	67,280	-	-	67,280
O&M production purchases - energy cost	-	362,709	-	-	362,709	-	-	362,709
O&M deferred fuel expense	-	(273 901)	-	-	(273 901)	-	-	(273 901)
Purchased power	-	156 088	-	-	156 088	-	-	156 088
Other O&M expense								
Labor expense	-	395,026	-	-	395,026	-	-	395,026
Pension & benef ts	-	73,211	-	-	73,211	-	-	73,211
Regulatory commission expense	-	6,804	-	-	6,804	-	-	6,804
Property insurance	-	(526)	-	-	(526)	-	-	(526)
Injuries & damages - workman's compensation	-	197	-	-	197	-	-	197
Uncollectible accounts	-	8,937	-	-	8,937	-	-	8,937
Other O&M expense	-	500,881	-	-	500,881	-	-	500,881
Adjust for other revenue	-	(1,105)	-	-	(1,105)	-	-	(1,105)
Adjust for non fuel riders/aviation/merger	-	(141,603)	-	-	(141,603)	-	-	(141,603)
Adjust for non-labor O&M	-	1,311	-	-	1,311	-	-	1,311
Adjust for rate case expense/reg assets & liab lities	-	2,304	-	-	2,304	-	-	2,304
Adjust for Severance	-	(23,366)	-	-	(23,366)	-	-	(23,366)
Adjust for Outside Services	-	(146)	-	-	(146)	-	-	(146)
Adjust for Ashev lle and CertainTeed	-	4,635	-	-	4,635	-	-	4,635
Other adjustments to regulatory fees and uncollectibles	-	-	-	-	-	-	-	-
Total Other O&M expenses	-	826 560	-	-	826 560	-	-	826 560
Depreciation | amortization | P&C losses								
Depreciation & amortization	-	767,186	-	-	767,186	-	-	767,186
Adjust other amortization expense	-	(31 642)	-	-	(31 642)	-	-	(31 642)
Total depreciation & amortization expense	-	735 544	-	-	735 544	-	-	735 544
Taxes other than income taxes								
Payroll taxes	-	25,242	-	-	25,242	-	-	25,242
Property taxes	-	78,797	-	-	78,797	-	-	78,797
Other taxes - federal heavy vehicle use tax	-	(1,665)	-	-	(1,665)	-	-	(1,665)
Other taxes - electric excise tax - SC	-	-	-	-	-	-	-	-
Other taxes - privilege tax	-	12,244	-	-	12,244	-	-	12,244
Miscellaneous taxes - NC	-	(5,218)	-	-	(5,218)	-	-	(5,218)
Miscellaneous taxes - SC & other states	-	1	-	-	1	-	-	1
Other taxes - PUC license tax - SC	-	-	-	-	-	-	-	-
Adjust costs recovered through non-fuel riders	-	(6,458)	-	-	(6,458)	-	-	(6,458)
Adjust to re lect retirement of Asheville Steam Generating Plant	-	(1 032)	-	-	(1 032)	-	-	(1 032)
Total taxes other than income taxes	-	101 911	-	-	101 911	-	-	101 911
Interest on customer deposits	-	7 971	-	-	7 971	-	-	7 971
Income taxes								
Federal income taxes	-	-	-	-	-	-	-	-
State income taxes	-	-	-	-	-	-	-	-
Income taxes - deferred	-	-	-	-	-	-	-	-
Adjust for Federal income taxes | Adjust NC income taxes for		-			-			-
rate change | Synchronize interest expense	-	(138,188)	-	-	(138,188)	-	-	(138,188)
Adjust costs recovered through non-fuel riders	-	63,161	-	-	63,161	-	-	63,161
Adjust for Federal & State income taxes	-	181 242	-	-	181 242	-	-	181 242
Total income taxes	-	106 215	-	-	106 215	-	-	106 215
Amortization of ITC	-	(3 581)	-	-	(3 581)	-	-	(3 581)
Total electric operating expenses	-	2 764 333	-	-	2 764 333	-	-	2 764 333
Interest expense	1,348 11/	208,519 1 /	-	(750) 18/	207,769 21/	-	598	207,769
Income available for common equity	2 088 11/	456 612 15/	-	(1 643) 18/	454 969 22/	-	309 945	454 969
Net operating income for return	3 436	665 131	-	(2 393)	662 738	-	310 543	662 738
Total requirement	3 436	3 429 464	-	(2 393)	3 427 071	-	310 543	3 427 071
Cumulative change in working capital			$9,886			$9,611		$9,611
Rate base under present rates			10 100 532			10 100 532		10 100 532
Rate base after rate increase			$10 110 418			$10 110 143		$10 110 143
Overa l rate of return (L78 / L82)			6.58%			6.56%		6.56%
Target rate of return			6.56% 3/			6.56% 3/		6.56% 3/

11/ Column (g) minus Column (d).
12/ Column (d) plus Column (f), unless footnoted otherwise.
13/ Column (g), Line 79.
14/ Line 82, Column (e) mu tiplied by 50.000% multiplied by 4.110%.
15/ Line 82, Column (e) mu tiplied by 50.000% multiplied by 9.000%.
16/ Column (f) divided by 365 days multiplied by Column (b).
17/ Column (j) minus Column (g).
18/ Column (j) minus Column (g).
19/ Column (g) plus Column (i), unless footnoted otherwise.
20/ Column (j), Line 79.
21/ Line 82 Column (h) multip ied by 50.000% multiplied by 4.110%.
22/ Line 82 Column (h) multip ied by 50.000% multiplied by 9.000%.
23/ Column (i) divided by 365 days multip ied by Column (b).
24/ Column (c) plus Column (f) plus Column (i).
25/ Column (a) plus Column (l), unless footnoted otherwise.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
NET OPERATING INCOME FOR RETURN
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3

Line No.	Item	Under Present Rates: NC Retail Adjusted Per Company 1/	Under Present Rates: Public Staff Adjustments 2/	Under Present Rates: After Public Staff Adjustments 3/	After Public Staff Recommended Increase: Rate Increase	After Public Staff Recommended Increase: After Rate Increase 7/
		(a)	(b)	(c)	(d)	(e)
1	Electric operating revenues:					
2	Sales of electricity	$3,339,374	$3,929	$3,343,303	$109,234 4/	$3,452,537
3	Other revenues	-	-	-	-	-
4	Electric operating revenues (Sum of L2 through L3)	$3,339,374	$3,929	$3,343,303	$109,234	$3,452,537
5	Electric operating expenses:					
6	Operations and maintenance:					
7	Fuel used in electric genera ion	835,224	(1,598)	833,626	-	833,626
8	Purchased power	156,798	(710)	156,088	-	156,088
9	O her operations and maintenance expenses	873,513	(46,952)	826,561	403 5/	826,964
10	Deprecia ion and amortization	971,156	(203,970)	767,186	-	767,186
11	General taxes	104,215	(2,305)	101,910	-	101,910
12	Interest on customer deposits	7,971	-	7,971	-	7,971
13	Net income taxes	38,082	60,711	98,793	25,170 6/	123,963
14	Amortization of protected EDIT, net of tax	-	(24,311)	(24,311)	-	(24,311)
15	Amortization of investment tax credit	(3,614)	34	(3,580)	-	(3,580)
16	Total electric opera ing expenses (Sum of L6 through L15)	2,983,345	(219,100)	2,764,245	25,573	2,789,818
17	Net operating income for return (L4 minus L16)	$356,029	$223,029	$579,058	$83,661	$662,719

1/ Based on updated Smith Exhibit 1.
2/ Dorgan Exhibit 1, Schedule 3-1, Column (ad).
3/ Column (a) plus Column (b).
4/ Dorgan Exhibit 1, Schedule 5, Line 5, Column (c).
5/ Line 4 imes (1 minus reten ion factor after uncollec ibles and regulatory fee of 0.9963091 from Dorgan Exhibit 1, Schedule 1-2, Line 10).
6/ (Line 4 minus Line 9) minus (increase in debt expense from Dorgan Exhibit 1, Schedule 5, Line 5, Column (a) mutiplied by composite income tax rate of 23.1693%).
7/ Column (c) plus Column (d).

DUKE ENERGY PROGRESS LLC
Docket No E 2 Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC S AFF NE OPERA ING INCOME AD US MEN S
For the est Year Ended December 31 2018
(Dollar Amounts Expressed in housands)

Public Staff
Dorgan Exhibit 1
Schedule 3 1
Page 1 of 4

Line No.	Item	Update P ant to 12/31/2019	Update Revenues/ Customer Growth/ Weather to 12/31/2019	Adjust Cred t Card Fees	Remove EDIT Refunds or Treatment as R ders	Include F owback of Protected EDIT due to Tax Cuts & Jobs Act	Adjust Deprec ation Rates	Adjust Salaries & Wages
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Electr c operating revenues:							
2	Sales of electr city	$0	$,09 /	$0	$0	$0	$0	$0
3	Other revenues	-	-	-	-	-	-	-
	Electr c operating revenues (Sum of L2 through L3)	-	,09	-	-	-	-	-
5	Electr c operating expenses:							
6	Operations and maintenance:							
7	Fuel used in electric generat on	-	(1,598) /	-	-	-	-	-
8	Purchased power	-	-	-	-	-	-	-
9	Other opera ions and maintenance expenses	-	(3,168) /	(91) 5/	-	-	-	1,932 8/
10	Deprec ation and amort zat on	(10,328) 3/	-	-	-	- 6/	(3,6 2) 7/	-
11	General taxes	(1,711) 3/	-	-	-	-	-	109 8/
12	Interest on customer depos ts	-	-	-	-	-	-	-
13	Net income taxes	2,789 2/	2,053 2/	21 2/	-	- 2/	10,112 2/	(73) 2/
1	Amortization of protected EDIT, net of tax	-	-	-	-	(2 ,311)	-	-
15	Amortization of investment tax credit	-	-	-	-	-	-	-
16	Total electric operating expenses (Sum of L6 through L15)	(9,250)	(2,713)	(70)	-	(2 ,311)	(33,530)	1,568
17	Net operating income for return (L minus L16)	9,250	6,807	70	-	2 ,311	33,530	(1,568)
18	Calcu ated revenue requirement impact 1/	($12,085)	($8,892)	($91)	$0	($31,760)	($ 3,803)	$2,0 8

1/ Negative of Line 16 div ded by equity retent on factor 0.7635890 from Dorgan Exhibit 1, Schedule 1-2, Line 1 .
2/ Line minus Sum of Lines 7 through 12 times composite income tax rate of 23.1693%.
3/ Dorgan Exhibit 1, Schedule 3-1(a).
/ Dorgan Exhibit 1, Schedule 3-1(b).
5/ Dorgan Exhibit 1, Schedule 3-1(c).
6/ Dorgan Exhibit 1, Schedule 3-1(d).
7/ Dorgan Exhibit 1, Schedule 3-1(e).
8/ Dorgan Exhibit 1, Schedule 3-1(f).

DUKE ENERGY PROGRESS LLC
Docket No E 2 Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC S AFF NE OPERA ING INCOME AD US MEN S
For the est Year Ended December 31 2018
(Dollar Amounts Expressed in housands)

Public Staff
Dorgan Exhibit 1
Schedule 3 1
Page 2 of 4

Line No.	Item		Adjust Incentives	Adjust Severance Costs	Adjust Executive Compensation	Adjust Av ation Expenses	Adjust Outside Services	Adjust to Norma ize Storm Costs	Adjust Storm Deferral
			(h)	( )	(j)	(k)	(l)	(m)	(n)
1	Electr c operating revenues:								
2	Sales of electr city		$0	$0	$0	$0	$0	$0	$0
3	Other revenues		-	-	-	-	-	-	-
	Electr c operating revenues (Sum of L2 through L3)		-	-	-	-	-	-	-
5	Electr c operating expenses:								
6	Operations and maintenance:								
7	Fuel used in electric generat on		-	-	-	-	-	-	-
8	Purchased power		-	-	-	-	-	-	-
9	Other operations and maintenance expenses		(1 ,652) 9/	(5,150) 10/	(160) 11/	(05) 12/	(1 6) 13/	9,300 1 /	-
10	Deprec ation and amort zat on		-	-	-	-	-	-	(,52) 15/
11	General taxes		-	-	-	(2) 12/	-	-	-
12	Interest on customer depos ts		-	-	-	-	-	-	-
13	Net income taxes		3,395 2/	1,193 2/	37 2/	9 2/	3 2/	(2,155) 2/	10,316 2/
1	Amortization of protected EDIT, net of tax		-	-	-	-	-	-	-
15	Amortization of investment tax credit		-	-	-	-	-	-	-
16	Total electric operating expenses (Sum of L6 through L15)		(11,257)	(3,957)	(123)	(313)	(112)	7,1 5	(3 ,208)
17	Net operating income for return (L minus L16)		11,257	3,957	123	313	112	(7,1 5)	3 ,208
18	Calcu ated revenue requirement impact	1/	($1 ,705)	($5,169)	($161)	($ 09)	($1 6)	$9,33	($,689)

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9/ Dorgan Exhib t 1, Schedu e 3-1(g).
10/ Dorgan Exhib t 1, Schedu e 3-1(h).
11/ Dorgan Exhib t 1, Schedu e 3-1(i).
12/ Dorgan Exhib t 1, Schedu e 3-1(j).
13/ Dorgan Exhib t 1, Schedu e 3-1(k).
1 / Dorgan Exhib t 1, Schedu e 3-1(l).
15/ Dorgan Exhib t 1, Schedu e 3-1(m).

DUKE ENERGY PROGRESS LLC
Docket No E 2 Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC S AFF NE OPERA ING INCOME AD US MEN S
For the est Year Ended December 31 2018
(Dollar Amounts Expressed in housands)

Public Staff
Dorgan Exhibit 1
Schedule 3 1
Page 3 of 4

Line No.	Item		Adjust Charitable Contribu ions, and Corporate Sponsorships & Donations	Adjust Lobbying Expense	Adjust Board of Directors Expense	Adjust EOL Nuclear M&S Reserve Amortizat on	Adjustment to Remove Deferred Environmental Costs - ARO	Adjustment to Remove Deferred Non-ARO Enviromental Costs	Adjustment to Remove CertainTeed Payment Ob igation	Adjustment to Inflation Adjustment
			(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
1	Electr c operating revenues:									
2	Sales of electr city		$0	$0	$0	$0	$0	$0	$0	$0
3	Other revenues		-	-	-	-	-	-	-	-
	Electr c operating revenues (Sum of L2 through L3)		-	-	-	-	-	-	-	-
5	Electr c operating expenses:									
6	Operations and maintenance:									
7	Fuel used in electric generat on		-	-	-	-	-	-	-	-
8	Purchased power		-	-	-	-	-	-	-	-
9	Other operations and maintenance expenses		(36) 16/	(1,538) 17/	(1,270) 18/	-	-	-	(,939) 21/	2,005 22/
10	Deprec ation and amort zat on		-	-	-	(1,807) 19/	(87,715) 20/	(,062) 20/	-	-
11	General taxes		-	-	-	-	-	-	-	-
12	Interest on customer depos ts		-	-	-	-	-	-	-	-
13	Net income taxes		8 2/	356 2/	29 2/	19 2/	20,323	9 1	1,1 2/	(65) 2/
1	Amortization of protected EDIT, net of tax		-	-	-	-	-	-	-	-
15	Amortization of investment tax credit		-	-	-	-	-	-	-	-
16	Total electric operating expenses (Sum of L6 through L15)		(28)	(1,182)	(976)	(1,388)	(67,392)	(3,121)	(3,795)	1,5 0
17	Net operating income for return (L minus L16)		28	1,182	976	1,388	67,392	3,121	3,795	(1,5 0)
18	Calcu ated revenue requirement impact	1/	($37)	($1,5)	($1,275)	($1,813)	($88,0 0)	($,077)	($,958)	$2,012

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16/ Dorgan Exhibit 1, Schedule 3-1(n).
17/ Dorgan Exhibit 1, Schedule 3-1(o).
18/ Dorgan Exhibit 1, Schedule 3-1(p).
19/ Dorgan Exhibit 1, Schedule 3-1(q).
20/ Based on recommendation of Publ c Staff witness Maness.
21/ Moved to fuel case docket per NCUC order
(Docket E-2, Sub 120).
22/ Dorgan Exhibit 1, Schedule 3-1(v).

DUKE ENERGY PROGRESS LLC
Docket No E 2 Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC S AFF NE OPERA ING INCOME AD US MEN S
For the est Year Ended December 31 2018
(Dollar Amounts Expressed in housands)

Public Staff
Dorgan Exh b t 1
Schedule 3 1

Line No.	Item	Adjustment to Nuclear Decommissioning Expense	Adjustment to Remove Rate Case Expense	Adjustment to COSS - SWP&A Rea location	Adjust Ashevil e CC Plant in Service Costs	Adjust Ashevil e CC Deferral	Adjust for Ashevil e Production Disp acement	Interest Synchroniza ion Adjustment	Total NOI Adjustments 30/
		(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)	(ad)
1	Electr c operating revenues:								
2	Sales of electr city	$0	$0	($165)	$0	$0	$0	$0	$3,929
3	Other revenues	-	-	-	-	-	-	-	-
	Electr c operating revenues (Sum of L2 through L3)	-	-	(165)	-	-	-	-	3,929
5	Electr c operating expenses:								
6	Operations and maintenance:								
7	Fuel used in electric generat on	-	-	-	-	-	-	-	(1,598)
8	Purchased power	-	-	(710) 25/	-	-	-	-	(710)
9	Other operations and maintenance expenses	(16,537) 23/	(3 6) 2 /	(1,922) 25/	(3,918) 26/	-	(5,910) 28/	-	(6,952)
10	Deprec ation and amort zat on	-	-	(6,579) 25/	-	(5,313) 27/	-	-	(203,970)
11	General taxes	-	-	(701) 25/	-	-	-	-	(2,305)
12	Interest on customer depos ts	-	-	-	-	-	-	-	-
13	Net income taxes	3,831 2/	80 2/	2,152 25/	908 2/	1,231 2/	1,369 2/	70 29/	60,711
1	Amortization of protected EDIT, net of tax	-	-	-	-	-	-	-	(2 ,311)
15	Amortization of investment tax credit	-	-	3 25/	-	-	-	-	3
16	Total electric operating expenses (Sum of L6 through L15)	(12,706)	(266)	(7,726)	(3,010)	(,082)	(,5 1)	70	(219,100)
17	Net operating income for return (L minus L16)	12,706	266	7,561	3,010	,082	,5 1	(70)	223,029
18	Calcu ated revenue requirement impact 1/	($16,599)	($3 8)	($9,878)	($3,932)	($5,333)	($5,933)	$920	($291,362)

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23/ Per Recommendation of Public Staff witness Hinton.
2 / Dorgan Exhibit 1, Schedule 3-1(r).
25/ Dorgan Exhibit 1, Schedule 3-1(s).
26/ Dorgan Exhibit 1, Schedule 3-1(t).
27/ Dorgan Exhibit 1, Schedule 3-1(t)(1).
28/ Dorgan Exhibit 1, Schedule 3-1(u).
29/ Dorgan Exhibit 1, Schedule 3-1(w).
30/ Sum of Columns (a) through Column (ad).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO DEPRECIATION EXPENSE AND PROPERTY TAXES FOR PLANT UPDATE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(a)

Line No.	Item	Amount	
1	**Depreciation expense**		
2	Depreciation expense on increase in plant per Public Staff	$59,599	1/
3	Company Adjustment	69,927	2/
4	Public Staff adjustment to depreciation expense for update of plant (L2 - L3)	($10,328)	
5	**General taxes**		
6	Update to plant per Public Staff	$1,404,303	3/
7	Less: Adjustment to intangible plant	67,860	4/
8	Adjustment to plant excluding intangible plant (L6 - L7)	$1,336,443	
9	Average property tax rate	0.36259%	5/
10	Impact to property taxes of Public Staff update (L8 x L9)	$4,846	
11	Company Adjustment per Application/Update	6,557	6/
12	Public Staff adjustment to property taxes (L10 - L11)	($1,711)	

1/ Dorgan Exhibit 1, Schedule 3-1(a)(1), Line 10, Column (e).
2/ NCUC Form E-1, Item No. 10, NC-1001, Page 2, Line 78 (Total NC Retail column), as adjusted to SWPA.
3/ Dorgan Exhibit 1, Schedule 2-1(a)(1), Line 11, Column (g).
4/ Dorgan Exhibit 1, Schedule 2-1(a)(1), Line 10, Column (g).
5/ NCUC Form E-1, Item No. 10, NC-1001, Line 83.
6/ NCUC Form E-1, Item No. 10, NC-1001, Page 2, Line 90 minus Line 86, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF DEPRECIATION EXPENSE ON PLANT UPDATE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(a)(1)

Line No.	Item	Increase in Plant in Service 1/	Depreciation Rate 2/	Increase in Depreciation 4/	NC Retail Percentage 5/	NC Retail Amount 6/
		(a)	(b)	(c)	(d)	(e)
1	Steam plant	$294,580	4.13%	$12,166		
2	Hydro plant	9,473	3.65%	346		
3	Other production plant	531,117	5.03%	26,715		
4	Nuclear plant	338,812	3.31%	11,215		
5	Total production plant	1,173,982		50,442	60.8591%	$30,699
6	Transmission plant	225,925	2.23%	5,038	58.8448%	2,965
7	Distribution plant	522,212	2.32%	12,115	87.1486%	10,558
8	General plant	45,985	4.39%	2,019	73.7686%	1,489
9	Intangible plant	100,689	various 3/	20,607	67.3953%	13,888
10	Total	$2,068,794		$90,221		$59,599

1/ Dorgan Exhibit 1, Schedule 2-1(a)(1), Column (e).
2/ Based on recommendation of Public Staff witness McCullar, unless footnoted otherwise.
3/ Based on information provided by the Company.
4/ Column (a) times Column (b).
5/ NCUC Form E-1, Item No. 45B.
6/ Column (c) multiplied by Column (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO UPDATE REVENUES TO DECEMBER 31, 2019
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(b)

Line No.	Item	2/ Adjustment	3/
	Revenues		
1	Update revenues for customer growth	$58,730	1/
2	Update revenues for usage	(53,000)	2/
3	Update revenues for weather	(1,636)	3/
4	Adjust revenues for update (L1 + L2 + L3)	$4,094	
	Fuel and Fuel Related Expense		
5	Adjust fuel and fuel-related expense for customer growth update	$15,661	1/
6	Adjust fuel and fuel-related expense for usage update	(15,574)	2/
7	Adjust fuel and fuel-related expense for weather update	(1,685)	3/
8	Adjust fuel expense for change in kWh (L5 + L6 + L7)	($1,598)	
	Other O&M Expense		
9	Public Staff update adjustment to mWh sales for customer growth (kWh/1000)	816,845	1/
10	Public Staff update adjustment to mWh sales for customer usage (kWh/1000)	(662,788)	2/
11	Public Staff update adjustment to mWh sales for weather (kWh/1000)	(853,907)	3/
12	Public Staff adjustment to mWh sales (kHw/1000) (L9 + L10 + L11)	(699,850)	
13	Energy-related non-fuel variable O&M expense (in dollars per mWh)	5.82786	4/
14	Adjustment to energy-related non-fuel variable O&M expense (L12 x L13 / 1000)	($4,079)	
15	Public Staff change in bills	415,178	5/
16	Annual customer-related variable O&M expense per bill (in dollars)	2.15793	6/
17	Adjustment to customer-related variable O&M expense (L14 x L15 / 1,000)	$896	
18	Adjust variable non-fuel O&M expense (L14 + L17)	($3,183)	
19	Adjust uncollectibles for increase in revenues	10	7/
20	Adjust regulatory fee for increase in revenues, net of uncollect bles	5	8/
21	Total adjustment to other O&M expenses (L18 + L19 + L20)	($3,168)	

1/ Dorgan Exhibit 1, Schedule 3-1(b)(1), Line 21.
2/ Dorgan Exhibit 1, Schedule 3-1(b)(2), Line 20.
3/ Dorgan Exhibit 1, Schedule 3-1(b)(4), Line 7.
4/ Dorgan Exhibit 1, Schedule 3-1(b)(3), Line 24.
5/ Based on the recommendation of Public Staff witness Saillor.
6/ Dorgan Exhibit 1, Schedule 3-1(b)(5), Line 19.
7/ Line 4 times uncollectibles rate of 0.2394%.
8/ (Line 4 minus Line 19) multiplied by regulatory fee rate of 0.13%.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ADJUSTMENT TO REVENUES AND FUEL RELATED EXPENSES TO UPDATE CUSTOMER GROWTH TO DECEMBER 31, 2019
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(b (1)

		Revenues				
Line No.	tem	Public Staff Growth in NC KWH Adjustment 1/	Cents per KWH 2/	Public Staff Adjustment 3/	Fuel Costs in Cents per KWH 4/	Public Staff Adjustment 5/
		(a)	(b)	(c)	(d)	(e)
1	Residential excluding TOU	401,416,124	8.84	$35,485	2 3110	$9,277
2	Residential TOU	7,822,678	8.68	679	2 3110	181
3	Total NC Residential Service (L1 + L2)	409 238 802		$36 164		$9 458
4	SGS excluding Constant Load Rate	27,320,655	10.87	$2,970	2 5560	$698
5	SGS Constant Load Rate	1,026,005	11.25	115	2 5560	26
6	Total NC Small General Service (L4 + L5)	28,346,660		$3,085		$724
7	Medium General Service	97,394,300	6.19	$6,029	2.4770	$2,412
8	SGS Time of Use	129,131,822	6.74	8,703	2.4770	3,199
9	Seasonal and Intermittent Service	4,977,632	10.97	546	2.4770	123
10	Total NC Medium General Service (L7+ L8 + L9)	231,503,754		$15,278		$5,734
11	LGS excluding TOU and RTP	44,395,281	7.79	$3,458	1.7570	$780
12	LGS Time of Use	61,043,511	6.00	3,663	1.7570	1,073
13	LGS Real Time Pricing	41,368,330	4.78	1,977	1.7570	727
14	Total NC Large General Service (L11+ L12 + L13)	146,807,122		$9,098		$2,580
15	Street Lighting	23,431	17.84	$4	2 2510	$1
16	Sports Field Lighting	915,635	30.85	282	2 2510	21
17	Traffic Signal Lighting	9,235	9.20	1	2 2510	-
18	Total Area and Outdoors Lighting - NC Retail (L15 + L16 + L17)	948,301		$287		$22
19	Total NC Retail (L3 + L6 + L10 + L14 + L18)	816 844 639		$63,912		$18,518
20	Company Adjustments			5 182 6/		2 857 6/
21	Public Staff adjustment to revenues			$58 730		$15 661

1/ Amounts per Public Staff witness Saillor.
2/ NCUC Form E-1, tem No. 10, NC-0402, Column (b), updated to December 31, 2019 per Company response to PSDR 1-7.
3/ (Column (a) times Column (b)) divided by 100,000.
4/ NCUC Form E-1, tem No. 10, NC-0401, Line 4.
5/ (Column (a) times Column (d)) divided by 100,000.
6/ NCUC Form E-1, tem No. 10, NC-0401, Total NC Retail Column, Lines 2 and 6, as adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ADJUSTMENT TO REVENUES AND FUEL RELATED EXPENSES TO UPDATE USAGE TO DECEMBER 31, 2019
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(b)(2)

Line No.	Item	Revenues: Public Staff Usage in NC KWH Adjustment 1/	Revenues: Cents per KWH 2/	Revenues: Public Staff Adjustment 3/	Fuel Costs in Cents per KWH 4/	Public Staff Adjustment 5/
		(a)	(b)	(c)	(d)	(e)
1	Residential excluding TOU	(304,751,223)	8.84	($26,940)	2 3110	($7,043)
2	Residential TOU	(5 938 901)	8.68	(515)	2 3110	(137)
3	Total NC Residential Service (L1 + L2)	(310,690,124)		($27,455)		($7,180)
4	SGS excluding Constant Load Rate	(57,938,430)	10.87	($6,298)	2 5560	($1,481)
5	SGS Constant Load Rate	(2,175,831)	11.25	(245)	2 5560	(56)
6	Total NC Small General Service (L4 + L5)	(60 114 261)		($6 543)		($1 537)
7	Medium General Service	(95,116,680)	6.19	($5,888)	2.4770	($2,356)
8	SGS Time of Use	(126,112,002)	6.74	(8,500)	2.5560	(3,223)
9	Seasonal and Intermittent Service	(4,861,227)	10.97	(533)	2.4770	(120)
10	Total NC Medium General Service (L7+ L8 + L9)	(226,089,909)		($14,921)		($5,699)
11	LGS excluding TOU and RTP	(19,932,698)	7.79	($1,553)	1.7570	($350)
12	LGS Time of Use	(27,407,460)	6.00	(1,644)	1.7570	(482)
13	LGS Real Time Pricing	(18 573 651)	4.78	(888)	1.7570	(326)
14	Total NC Large General Service (L11+ L12 + L13)	(65,913,809)		($4,085)		($1,158)
15	Total NC General (L3 + L6 + L10 + L14)	(662,808,103)		($53 004)		($15 574)
16	Street Lighting	-	30.85	-	2 2510	-
17	Traffic Signal Lighting	-	9.20	-	2 2510	-
18	Sports Field Lighting	20,245	17.84	4	2 2510	-
19	Total NC Street Lighting (L15 + L16 + L17)	20 245		4		-
20	Total NC Retail (L15 + L19)	(662 787 858)		($53 000)		($15 574)

1/ Amounts per Public Staff witness Saillor.
2/ NCUC Form E-1, tem No. 10, NC-0402, Column (b), updated to December 31, 2019 per Company response to PSDR 1-7.
3/ (Column (a) times Column (b)) divided by 100,000.
4/ NCUC Form E-1, tem No. 10, NC-0401, Line 4.
5/ (Column (a) times Column (d)) divided by 100,000.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF VARIABLE NON-FUEL O&M EXPENSE PER MWH
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(b)(3)

Line No.	tem	NC Retail Amount		Sub-Calculations	
		(a)		(b)	
1	2018 per books energy-related production O&M expense excluding fuel and purchased power	$346,881	1/		
2	Non-fuel rider energy-related costs removed from base rates	(135,418)	2/		
3	Total non-fuel, non-payroll energy related production O&M expense (L1 - L2)	$211,463			
4	Total O&M expense, excluding A&G expense	2,816,946	3/		
5	Less: fuel expense	1,115,110	4/		
6	Total non-fuel O&M expense, excluding A&G expense (L4 - L5)	1,701,836			
7	Ratio (L3 / L6)	0.124256			
8	Total per books A&G expense	$302,537	5/		
9	Salaries and wages - system amount			$144,924	6/
10	Per books employee pensions and benefits - system amount			133,210	7/
11	Subtotal (L9 + L10)			$278,134	
12	NC Retail Allocation Factor			65.8950%	8/
13	NC retail per books - salaries, wages, pensions, and employee benefits (L11 x L12)			$183,276	
14	Aviation expense removed elsewhere			1,857	9/
15	NC regulatory fee adjusted elsewhere			3,274	10/
16	Outside services removed elsewhere			146	11/
17	Sponsorships and donations removed elsewhere			36	12/
18	Board of Directors expense removed elsewhere			1,270	13/
19	Total of A&G items adjusted elsewhere (Sum of Lines 13 through L18)	189,859		$189 859	
20	Total A&G expense not adjusted elsewhere (L8 - L18)	$112,678			
21	Portion of A&G not adjusted elsewhere related to non-fuel non-payroll energy-related production O&M expense (L7 x L20)	14,001			
22	Total non-fuel, non-payroll energy-related production O&M expense plus related non-payroll A&G expense (L3 + L21)	$225,464			
23	Per books NC retail mWh sales	38,687,268	14/		
24	Cost per mWh (in dollars) (L22 x 1,000 / L23)	$5.82786			

1/ NCUC Form E-1, Item No. 45B, SWPA, Total Production O&M-Energy.
2/ NCUC Form E-1, Item No. 10, NC-0601, Other O&M expense excluding Line 23, Total NC Retail Column, adjusted to SWPA.
3/ NCUC Form E-1, Item No. 45B, SWPA, NC Retail Column, O&M expenses, Total of Tab 1.
4/ NCUC Form E-1, Item No. 10, NC-0201, Total NC Retail Column, Sum of Lines 2, 4, and 5; adjusted to SWPA.
5/ NCUC Form E-1, Item No. 45B, SWPA, A&G expenses, Tab 2.
6/ NCUC Form E-1, Item No. 10, NC-1306, Line 27.
7/ NCUC Form E-1, Item No. 10, NC-1309, Line 6.
8/ NC Retail Allocation Factor: SWPA - LAB (labor).
9/ NCUC Form E-1, Item No. 10, NC-1701, Line 2 plus Dorgan Exhibit 1, Schedule 3-1(m), Line 9 plus Line 21.
10/ NCUC Form E-1, Item 10, NC-3101, Line 7.
11/ Dorgan Exhibit 1, Schedule 3-1(k), Line 6.
12/ Dorgan Exhibit 1, Schedule 3-1(n), Line 6.
13/ Dorgan Exhibit 1, Schedule 3-1(p), Line 15.
14/ NCUC Form E-1, Item No. 10, NC-0201, Line 15 divided by 1,000.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ADJUSTMENT TO TEST YEAR REVENUES AND FUEL RELATED EXPENSES FOR WEATHER
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(b)(4)

		Revenues			Fuel & Fuel Related Expenses	
Line No.	Item	Public Staff NC KWH Weather Adjustment 1/	Cents per KWH 2/	Public Staff Adjustment 3/	Fuel Costs in Cents per KWH 4/	Public Staff Adjustment 5/
		(a)	(b)	(c)	(d)	(e)
1	Total NC Residential	(610,804,624)	10.0110	($61,148)	2.3110	($14,116)
2	Total NC Small General Service	(29,797,487)	10.8770	(3,241)	2.5560	(762)
3	Total NC Medium General Service	(172,201,436)	7.2470	(12,479)	2.4770	(4,265)
4	Total NC Large General Service	(41,103,239)	5.2550	(2,160)	1.7570	(722)
5	Total NC Retail (L1 + L2 + L3 + L4)			($79,028)		($19,865)
6	Company Adjustment			(77,392) 6/		(18,180) 6/
7	Public Staff adjustment to revenues (L5 - L6)	(853,906,786)		($1,636)		($1,685)

1/ Amounts per Public Staff witness Saillor.
2/ NCUC Form E-1, Item No. 10, NC-0301, Line 10, updated to December 30, 2019.
3/ (Column (a) times Column (b)) divided by 100,000.
4/ NCUC Form E-1, Item No. 10, NC-0301, Line 14, updated to December 30, 2019.
5/ (Column (a) times Column (d)) divided by 100,000.
6/ NCUC Form E-1, Item No. 10, NC-0301, Line 13, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF BILL-RELATED EXPENSES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(b)(5)

Line No.	Item	NC Retail Amount (a)		Sub-Calculations (b)	
1	2018 per books bill-related O&M expenses:				
2	Account 586 - Meters (operation)	$6,592	1/		
3	Account 587 - Customer - installations	4,525	1/		
4	Accounts 901-905 - Customer accounts	49,620	2/		
5	Accounts 908-910 - Customer service and information	3,202	2/		
6	Total 2018 per books bill-related expenses (Sum of Lines 2 through 5)	$63,939			
7	Salaries and wages included in Line 6 - system amount			30,686	3/
8	NC Retail Allocation Factor			65.8950%	4/
9	NC retail salaries and wages included in Line 7 (L7 x L8)	20,221		$20,221	
10	Uncollectibles expense adjusted elsewhere	8,937	5/		
11	Total non-payroll bill-related O&M expenses not adjusted elsewhere (L6 - L9 - L10)	$34,781			
12	Total O&M expense, excluding A&G expense	2,816,946	6/		
13	Total non-fuel O&M expense, excluding A&G expense	1 701 836	7/		
14	Ratio (L11 / L13)	0 020437			
15	Total A&G expense not adjusted elsewhere	$112,678	8/		
16	Portion of A&G not adjusted elsewhere related to non-payroll bill-related O&M expense (L14 x L15)	$2,303			
17	Total non-payroll bill-related O&M expenses plus related non-payroll A&G expense (L11 + L16)	$37,084			
18	Per books NC retail 2018 bills	17,184,948	3/		
19	Cost per bill ($) (L17 x 1,000 / L18)	$2.15793			

1/ NCUC Form E-1, Item No. 45A, SWPA, Lines 198 and 221.
2/ NCUC Form E-1, Item No. 45A, SWPA, Lines 240 and 246.
3/ Based on information provided by Company.
4/ NC Retail Allocation Factor: SWPA - LAB (labor).
5/ NCUC Form E-1, Item No. 45A, SWPA, Account 904 - Uncollectible Accounts, Line 238, NC Retail amount.
6/ Dorgan Exhibit 1, Schedule 3-1(b)(3), Line 4.
7/ Dorgan Exhibit 1, Schedule 3-1(b)(3), Line 6.
8/ Dorgan Exhibit 1, Schedule 3-1(b)(3), Line 20.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO PAYMENT CARD FEES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(c)

Line No.	Item	Amount	
1	Annualized 2018 residential payment card transacations	3,060,671	1/
2	Annualized 2019 residential payment card transactions	3,517,953	2/
3	Increase in annualized residential payment card transactions (L2 - L1)	457,282	
4	Transaction fees included in COS for non-payment card transactions	0.1990	3/
5	Remove O&M transaction costs included in COS (-L3 x L4 /1000)	($91)	

1/ Per Company response to PSDR 31-1.
2/ Per Company response to PSDR 1-7 and NCUC Form E-1, Item No. 10, NC-2503, Line 16 (December 2019 update).
3/ Based on information provided by Company.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO FLOWBACK PROTECTED EDIT DUE TO TAX CUTS AND JOBS ACT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(d)

Line No.	Item	Amount	
	Income Statement Impact		
1	Annual amortization of protected EDIT - NC retail	(31,642)	1/
2	Income tax impact	7,331	2/
3	Annual amortization of protected EDIT - NC retail, net of tax (L1 + L2)	($24,311)	
	Rate Base Impact		
4	Adjustment to regulatory assets and liabilities (-L3)	$31,642	
5	Composite income tax rate	23.1693%	3/
6	Impact to accumulated deferred income taxes (-L4 x L5)	(7,331)	
7	Adjustment to rate base (L4 + L6)	$24,311	

1/ Smith Exhibit 4, Column (a), Line 11.
2/ Line 1 times negative composite tax rate on Line 5.
3/ Dorgan Exhibit 1, Schedule 1-3, Line 8.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT FOR CHANGE IN DEPRECIATION RATES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(e)

Line No.	Item	Total System (a)		NC Retail Percentage (b)		NC Retail Amount (c)	
			1/		2/		
	Change in depreciation and amortization per Public Staff						
1	Production	$76,506		60.8591%	2/	$46,561	6/
2	Transmission	8,514		58.8448%	3/	5,010	6/
3	Distribution	(12,537)		87.1486%	4/	(10,926)	6/
4	Distribution COR adjustment - directly assigned	-		100.0000%		-	6/
5	General	(4,765)		73.7686%	5/	(3,515)	6/
6	General Plant Amortization	9,544		73.7686%	5/	7,041	6/
7	Adjust to deprec. and amort. for costs recovered in riders	1,362		60.8591%	2/	829	6/
8	Public Staff adjustment to depreciation and amortization expense	$78,625				45,000	
9	Company Adjustment per Application/Update					88,642	7/
10	Adjustment to depreciation and amortization expense (L8 - L9)					($43,642)	
11	Adjustment to accumulated depreciation (-L10)					$43,642	

1/ Based on recommendation of Public Staff witness McCullar.
2/ NCUC Form E-1, Item No. 45B, NC Retail Allocation Factor - DPALL, adjusted to SWPA.
3/ NCUC Form E-1, Item No. 45B, NC Retail Allocation Factor - DTALL, adjusted to SWPA.
4/ NCUC Form E-1, Item No. 45B, NC Retail Allocation Factor - RB PLT O DI, adjusted to SWPA.
5/ NCUC Form E-1, Item No. 45B, NC Retail Allocation Factor - NC Retail Allocation Factor - RB PLT O GN, adjusted to SWPA.
6/ Column (a) multiplied by Column (b).
7/ NCUC Form E-1, Item No. 10, NC-2601, Line 12, Total NC Retail Column, as adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO SALARIES AND WAGES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(f)

Line No.	Item	Duke Energy Carolinas (a)	Duke Energy Progress (b)	Service Company (DEBS) (c)	Total (d)
1	Labor per payroll company at December 31, 2019	$798,721 1/	$439,864 1/	$754,898 1/	
2	December 2019 allocation percentages	10 23% 1/	91.62% 1/	17.37% 1/	
3	Annualized salaries as of December 31, 2019 per Public Staff (L1 x L2)	81,695	403,016	131,099	
4	Per books salaries	85,883 2/	425,470 2/	133,040 2/	
5	Public Staff adjustment to salaries and wages for employees	(4,188)	(22,454)	(1,941)	($28,584) 4/
6	Company Adjustment	(4 492) 3/	(27 510) 3/	216 3/	(31 786) 4/
7	Adjustment to salaries and wages (L5 - L6)	$304	$5 056	($2 157)	3,202
8	Public Staff adjustment to total salaries and wages (L7)				$3,203
9	Percent charged to electric expense				75.98% 5/
10	Adjustment to net electric O&M salaries and wages (L8 x L9)				$2,433
11	Adjustment to net electric O&M salaries and wages (L10)				$2,433
12	Fringe benefits contribution rate				20.50% 6/
13	Adjustment to fringe benefits (L11 x L12)				$499
14	Total adjustment to O&M expense - total system (L10 + L13)				$2,932
15	NC Retail Allocation Factor				65.8950% 7/
16	Total adjustment to O&M expense - NC retail (L14 x L15)				$1 932
17	Impact on payroll taxes before Medicare				$130 8/
18	Impact on Medicare payroll taxes				35 9/
19	Adjustment to payroll taxes - total system (L17 + L18)				$165
20	NC Retail Allocation Factor				65.8950% 7/
21	Adjustment to payroll taxes - NC retail (L19 x L20)				$109

1/ Per Company response to DR1-7 and NCUC E-1, Item 10, NC-1304 updated as of December 31, 2019.
2/ NCUC E-1, tem 10, NC-1301, Labor per Books Column.
3/ Smith Exhibit 1, NC-1301, Lines 3, 4, and 5 Pro Forma HR Salaries Column, adjusted to SWPA.
4/ Sum of Columns (a) through (c).
5/ Smith Exhibit 1, NC-1301, Line 16.
6/ Smith Exhibit 1, NC-1301, Line 34.
7/ NC Retail Allocation Factor: SWPA - LAB (labor).
8/ Line 10 times 86.49% subject to OASDI times 6 2% OASDI tax rate from NC-1301.
9/ Line 10 times 1.45% Medicare tax rate from NC-1301, Line 27.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO INCENTIVES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(g)

Line No.	Item	Amount	
	Short Term Incentive Plan (STIP)		
1	Total Company STIP pay accrued expense associated with earnings per share (EPS)	$88,522	1/
2	Total Company STIP accrual	341,536	1/
3	Percentage of STIP related to EPS	25.92%	
4	STIP at target level associated with O&M expense per Company	69,054	2/
5	Adjustment to remove STIP related to EPS outcomes - total system (L3 x -L4)	(17,899)	
6	NC Retail Allocation Factor	65.8950%	3/
7	Adjustment to remove STIP related to EPS outcomes - NC retail (L5 x L6)	(11,795)	
8	Executive STIP already removed in executive compensation adjustment	87	4/
9	Adjustment to STIP (L7 + L8)	($11,708)	
	Long Term Incentive Plan (LTIP)		
10	Performance shares for EPS at target	$7,249	5/
11	Percentage associated with EPS and TSR	75.00%	
12	Adjustment to remove LTIP associated with EPS and TSR - total system (-L10 x L11)	(5,437)	
13	NC Retail Allocation Factor	65.8950%	3/
14	Adjustment to remove LTIP associated with EPS and TSR - NC retail (L12 x L13)	(3,583)	
15	Executive LTIP already removed in executive compensation adjustment	639	4/
16	Adjustment to LTIP (L14 + L15)	($2,944)	
17	Total adjustment to incentive pay (L9 + L16)	($14,652)	

1/ Company Response to Public Staff Data Request No. 32, Item 10.
2/ NCUC Form E-1, Item No. 10, NC-1310, Line 6.
3/ NC Retail Allocation Factor: SWPA - LAB (labor).
4/ Based on executive compensation adjustment.
5/ NCUC Form E-1, Item 10, NC-1310-3, Page 1, Line 13, Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO SEVERANCE COSTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(h)

Line No.	Item	Amount	
	Income Statement Impact		
1	Remove actual severance costs in 2018	($52,304)	1/
2	Annual amortization related to severance costs based on 5 year amortization	9,199	2/
3	Total Carolinas adjustment to remove actual severance costs (L1 + L2)	(43,105)	
4	NC Retail Allocation Factor	65.8950%	3/
5	NC Retail adjustment to remove severance costs (L3 x L4)	(28,404)	
6	Company adjustment	(23,254)	4/
7	Public Staff adjustment to O&M related to severance costs (L5 - L6)	($5,150)	
	Rate Base Impact		
8	Impact to working capital investment per Company	$20,206	5/
9	Impact to working capital investment per Public Staff	0	6/
10	Adjustment to working capital investment (L9 - L8)	($20,206)	
11	Impact to ADIT per Company	($4,682)	7/
12	Impact to ADIT per Public Staff	0	6/
13	Adjustment to ADIT (L12 - L11)	$4,682	

1/ NCUC Form E-1, Item No. 10, NC-2001, Total System Column, Line 2 updated to December 31, 2019 in Company response to PSDR-1, Item 7.
2/ NCUC Form E-1, Item No. 10, NC-2001, Total System Column, Line 3, updated to December 31, 2019, recalculated using a 5 year amortization period.
3/ NC Retail Allocation Factor: SWPA - LAB (labor).
4/ NCUC E-1, Item No. 10, NC-2001, Total NC Retail Column, Line 4, adjusted to SWPA.
5/ NCUC E-1, Item No. 10, NC-2001, NC Retail Column, Line 14, updated to December 31, 2019 and SWPA.
6/ Public Staff recommendation.
7/ NCUC E-1, Item No. 10, NC-2001, NC Retail Column, Line 17, updated to December 31, 2019 and SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO EXECUTIVE COMPENSATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(i)

Line No.	Item	Amount	
1	Executive compensation for top 5 executives per Company	$7,246	1/
2	Inclusion of executive benefits in adjustment	486	2/
3	Executive compensation subject to exclusion adjustment per Public Staff (L1 + L2)	$7,732	
4	NC Retail Allocation Factor	65.8950%	3/
5	NC retail portion of executive compensation subject exclusion adjustment (L3 x L4)	$5,095	
6	Exclusion percentage	50.00%	4/
7	Public Staff adjustment to exclude executive compensation (L6 x L7)	($2,548)	
8	Company adjustment	(2,387)	5/
9	Adjustment to remove additional executive compensation (L7 - L8)	($160)	

1/ NCUC Form E-1, Item No. 10, NC-0701, Line 3.
2/ Based on Company response to PSDR-41, Item 2.
3/ NC Retail Allocation Factor: SWPA - LAB (labor).
4/ NCUC Form E-1, Item No. 10, NC-0701, Line 10.
5/ NCUC Form E-1, Item No. 10, NC-0701, Line 11, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO AVIATION EXPENSES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(j)

Line No.	Item	Amount	
	Wages, benefits, materials, etc.		
1	Corporate aviation O&M and depreciation expense	$4,386	1/
2	Percentage to be excluded per Public Staff	56.95%	2/
3	Corporate aviation expenses to be excluded per Public Staff (L1 x L2)	$2,498	
4	Specific charter flights to be excluded	-	
5	Total corporate aviation expenses to be excluded per Public Staff (L3 + L4)	$2,498	
6	Company adjustment	2,193	3/
7	Additional aviation O&M expenses to be excluded (L5 - L6)	$305	
8	NC Retail Allocation Factor	65.8950%	4/
9	Public Staff adjustment to aviation O&M expenses (-L7 x L8)	($201)	
	General taxes		
10	Corporate aviation general taxes	$53	5/
11	Percentage to be excluded per Public Staff	56.95%	2/
12	Corporate aviation general taxes to be excluded per Public Staff (L10 x L11)	$30	
13	Company adjustment	27	6/
14	Additional aviation general taxes to be excluded (L12 - L13)	$3	
15	NC Retail Allocation Factor	65.8950%	4/
16	Public Staff adjustment to aviation general taxes (-L14 x L15)	($2)	
	Commercial flights		
17	International flight expense	$1,325	7/
18	Allocation percentage from DEBS to DEP	23.35%	8/
19	International flight expense allocated to DEP (L17 x L18)	$309	
20	NC Retail Allocation Factor	65.8950%	4/
21	Public Staff adjustment to O&M for commercial flights (-L19 x L20)	($204)	

1/ NCUC Form E-1, Item No. 10, NC-1702, Line 19.
2/ Calculated by Public Staff based on Company response to Public Staff Data Requests.
3/ NCUC Form E-1, Item No. 10, NC-1702, Line 22.
4/ NC Retail Allocation Factor: SWPA - LAB (labor).
5/ NCUC Form E-1, Item No. 10, NC-1702, Line 1, Total Duke Energy Progress Column.
6/ NCUC Form E-1, Item No. 10, NC-1702, Line 3, Total Duke Energy Progress Column.
7/ Calculated by Public Staff based on Company response to Public Staff Data Requests.
8/ Based on Company response to PSDR-28, Item 7(b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO OUTSIDE SERVICES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(k)

Line No.	Item	Amount	
1	Remove items related to coal ash litigation	$179	1/
2	Remove items identified that Company has agreed to remove	19	1/
3	Remove additional items identified by Public Staff that should be removed	42	1/
4	Total Public Staff adjustment to outside services (L1 + L2 + L3)	$239	
5	NC Retail Allocation Factor	60.8591%	2/
6	Public Staff adjustment to outside services - NC retail (-L4 x L5)	($146)	

1/ Based on information provided by Company in response to PSDR-75, Items 1 and 2, and advice of legal counsel.

2/ NC Retail Allocation Factor: SWPA - DP (production demand).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO NORMALIZE STORM COSTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(l)

Line No.	Item	Amount	
	Normalized storm expense		
1	NC retail amount of storm costs considered normal for 2018	$25,065	1/
2	NC Retail Allocation Factor	83.9171%	2/
3	2018 storm costs to be included in calculation of normalized level (L1 / L2)	29,869	
4	2010 through 2019 costs adjusted for inflation, excluding 2018	114,099	3/
5	Total storm costs for ten years adjusted for inflation (L3 + L4)	143,968	
6	Number of years	10	
7	Normalized level of storm costs - total system (L5 x L6)	14,397	
8	NC Retail Allocation Factor	83.9171%	2/
9	Normalized level of storm costs per Public Staff (L7 x L8)	12,082	
10	2018 Storm costs	2,782	4/
11	Total Public Staff adjustment to storm expense (L11 + L12)	9,300	

1/ NCUC Form E-1, Item No. 10, NC-2905, Line 2, NC Retail column, updated to December 31, 2019.
2/ NC Retail Allocation Factor: SWPA - RB_PLT_O_DI_OH_LN (distribution plant, overhead lines).
3/ Per Company response to PSDR 27-1, and storm costs included in Sub 1142.
4/ Per Company response to PSDR 27-1.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO STORM DEFERRAL
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(m)

Line No.	Item	Amount	
	Income Statement Impact		
1	Impact to depreciation and amortization for storm deferral per Company	$44,513	1/
2	Impact to depreciation and amortization to remove storm assets from rate base	(11)	2/
3	Impact to depreciation and amortization for storm deferral per Public Staff	-	3/
4	Adjustment to deprecation and amortization for storm deferral (L1 + L2 + L3)	(44,524)	
	Rate Base Impact		
5	Projected storm deferral balance per Company	$623,180	4/
6	Projected storm deferral balance per Public Staff	-	3/
7	Adjustment to working capital for storm deferral (L6 - L5)	($623,180)	
8	Impact to ADIT for storm deferral per Company	($144,387)	5/
9	Impact to ADIT for storm deferral per Public Staff	-	3/
10	Adjustment to ADIT for storm deferral (L9 - L8)	$144,387	
11	Adjustment to remove storm assets from rate base	($18,133)	2/
12	Adjustment to remove accumulated depreciation for storm assets from rate base	9	2/
13	Adjustment to rate base to remove storm assets (L11 + L12)	($18,124)	

1/ NCUC Form E-1, Item No. 10, NC-2901, Line 4, updated to December 31, 2019 and adjusted to SWPA.
2/ Provided by Company.
3/ Public Staff recommendation to remove storm deferral for securitization.
4/ NCUC Form E-1, Item No. 10, NC-2901, Line 16, updated to December 31, 2019 and adjusted to SWPA.
5/ NCUC Form E-1, Item No. 10, NC-2901, Line 19, updated to December 31, 2019 and adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO CHARITABLE CONTRIBUTIONS, CORPORATE SPONSORSHIPS, AND CORPORATE DONATIONS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(n)

Line No.	Item	Amount	
1	Remove charitable contributions not sought for recovery	$13	1/
2	Remove corporate sponsorships not sought for recovery and miscellaneous dues	37	2/
3	Removal of corporate donations and membership dues related to unregulated products	9	3/
4	Total sponsorships and donations to be removed per Public Staff (L1 + L2 + L3)	$59	
5	NC Retail Allocation Factor	60.8591%	4/
6	Public Staff adjustment to remove charitable contributions and corporate sponsorships & donations - NC retail (-L4 x L5)	($36)	

1/ Company Response to PSDR 34-4.
2/ Company Response to PSDR 34-3.
3/ Company Response to PSDR 34-6.
4/ NC Retail Allocation Factor: SWPA - DP (production demand).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO LOBBYING EXPENSE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(o)

Line No.	Item	Amount	
1	Remove Stakeholder Engagement O&M charges related to lobbying	$1,343	1/
2	Remove State Government Affairs O&M charges related to lobbying	94	1/
3	Remove Federal Affairs O&M charges related to lobbying	992	2/
4	Remove Edison Electric Institute (EEI) O&M charges related to lobbying	99	1/
5	Total lobbying costs to be removed from O&M expense (L1 + L2 + L3 + L4)	$2,528	
6	NC Retail Allocation Factor	60.8591%	3/
7	Public Staff adjustment to remove lobbying costs (-L5 x L6)	($1,538)	

1/ Based upon Company response to PSDR-35, Item 2(g).
2/ Based on Company response to PSDR-35, Item 5, and NCUC Form E-1, Item 16(b).
3/ NC Retail Allocation Factor: SWPA - DP (production demand).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO BOARD OF DIRECTORS EXPENSE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(p)

Line No.	Item	Amount	
1	Total Board of Directors (BOD) cash compensation	$421	1/
2	Percentage of exclusion per Public Staff	50%	2/
3	Public Staff adjustment to BOD compensation (-L1 x L2)	($210)	
4	Board of Directors (BOD) expenses	$155	
5	Percentage of exclusion per Public Staff	50%	
6	Public Staff adjustment to BOD expenses (-L4 x L5)	($78)	
7	BOD insurance charged to DEP	3,514	3/
8	Percentage of exclusion per Public Staff	50%	2/
9	Public Staff adjustment to BOD insurance (-L7 x L8)	($1,757)	
10	BOD and executive members expenses allocated to DEP	81	4/
11	Percentage of exclusion per Public Staff	50%	2/
12	Public Staff adjustment to BOD and executive members expenses (-L10 x L11)	($41)	
13	Total Public Staff adjustment to BOD compensation and expenses (L3 + L6 + L9 + L12)	($2,086)	
14	NC Retail Allocation Factor	60.8591%	5/
15	Public Staff adjustment to BOD expenses - NC retail (L13 x L14)	($1,270)	

1/ Amount from 2018 Proxy Statement, allocated to DEP.
2/ Recommended by Public Staff.
3/ Company Response to PSDR-40, Items 2 and 4.
4/ Company Response to PSDR-40, Item 1(a).
5/ NC Retail Allocation Factor: SWPA - DP (production demand).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO END OF LIFE RESERVE FOR NUCLEAR MATERIALS AND SUPPLIES AMORTIZATION EXPENSE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(q)

Line No.	Item	Brunswick 1 (a)	Brunswick 2 (b)	Harris (c)	Robinson (d)	Total (e)
1	Inventory as of December 31, 2018	$97,698 1/	$97,698 1/	$126,342 1/	$75,117 1/	$396,855 7/
2	Adjustment to remove inventory	(2,335) 2/	(2,320) 2/	(2,400) 2/	(1,845) 2/	(8,900) 8/
3	Inventory balance per Public Staff (L1 + L2)	95,363	95,378	123,942	73,272	$387,955
4	Percentage of M&S with salvage value or transferrable	10% 8/	10% 8/	10% 8/	10% 8/	
5	Nuclear M&S inventory base for amortization per Public Staff (L3 x (1-L4))	85,827	85,840	111,548	65,945	
6	NC Retail Allocation Factor	60.859% 3/	60.859% 3/	60.859% 3/	60.859% 3/	
7	NC retail nuclear M&S base for amortization (L5 x L6)	52,234	52,241	67,887	40,134	
8	Less: Projected inventory reserve at 8/31/2020	11,309 4/	12,278 4/	9,071 4/	13,703 4/	
9	NC nuclear reserve required at rates effective date (L7 - L8)	40,925	39,963	58,816	26,431	
10	Years of remaining plant life	16.00 5/	14.00 5/	26.00 5/	10.00 5/	
11	NC retail annual expense for reserve per Public Staff (L9 / L10)	2,558	2,855	2,262	2,643	$10,318 8/
12	Amount required per Company	3,006 6/	3,295 6/	2,594 6/	3,230 6/	12,125 8/
13	Public Staff adjustment to nuclear M&S reserve amortization expense (L11 - L12)	($448)	($440)	($332)	($587)	($1,807)

1/ NCUC Form E-1, Item 10, NC-2803, Line 2, adjusted to SWPA.
2/ Total adjustment from Column (e) allocated based on inventory amounts from Line 1.
3/ NC Retail Allocation Factor: SWPA - DP (production demand).
4/ NCUC Form E-1, Item 10, NC-2803, Line 16, adjusted to SWPA.
5/ NCUC Form E-1, Item 10, NC-2803, Line 22, adjusted to SWPA.
6/ NCUC Form E-1, Item 10, NC-2803, Line 24, adjusted to SWPA.
7/ Sum of Columns (a) through (d).
8/ Based on recommendation of Public Staff witness Metz.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO RATE CASE EXPENSE AND AMORTIZATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(r)

Line No.	Item	Amount	
	Income Statement Impact		
1	Actual rate case expense incurred through December 31, 2019	$1,773	1/
2	Amortization period in years	5	2/
3	Annual normalized level of rate case expense per Public Staff (L1 / L2)	$355	
4	Annual normalized level of rate case expense per Company	701	3/
5	Adjustment to annual normalized rate case expense (L3 - L4)	($346)	
	Rate Base Impact		
6	Projected working capital after first year of amortization per Company	$2,670	4/
7	Public Staff recommended regulatory asset amount for rate case expense	0	
8	Adjustment to rate base for rate case expense (L6 - L7)	($2,670)	

1/ NCUC Form E-1, Item No. 10, NC-1602, Line 13 through 25, updated to December 31, 2019.
2/ NCUC Form E-1, Item No. 10, NC-1601, Line 5.
3/ NCUC Form E-1, Item No. 10, NC-1601, Line 6.
4/ NCUC Form E-1, Item No. 10, NC-1601, Line 18.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
NET OPERATING INCOME, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(s)

Line No.	Item	North Carolina Retail Operations: SWPA Company NOI Reallocated By Public Staff 1/	Summer CP Company NOI - Company Allocations 2/	Cost of Service Study Adjustments 3/
		(a)	(b)	(c)
1	Electric operating revenue	$3,339,209	$3,339,374	($165)
	Electric operating expenses:			
	Operation and maintenance:			
2	Fuel used in electric generation	$835,224	$835,224	$0
3	Purchased power	156,088	156,798	(710)
4	Other operation and maintenance expense	871,591	873,513	(1,922)
5	Depreciation and amortization	964,577	971,156	(6,579)
6	General taxes	103,514	104,215	(701)
7	Interest on customer deposits	7,971	7,971	-
8	Net income taxes	40,234	38,082	2,152
9	Amortization of investment tax credit	(3,580)	(3,614)	34
10	Total electric operating expenses (Sum of L2 through L9)	$2,975,618	$2,983,345	($7,726)
11	Operating income (L1 - L10)	$363,590	$356,029	$7,561

1/ Dorgan Exhibit III, Schedule 2, Column (c).
2/ Dorgan Exhibit I, Schedule 3, Column (a).
3/ Column (a) - Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO ASHEVILLE COMBINED CYCLE PRO FORMA O&M EXPENSE AND REGULATORY ASSET
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(t)

Line No.	Item	NC Retail Amount	
	Income Statement Impact		
1	Average Annual Asheville Combined Cycle O&M - NC Retail per Company	$6,087	1/
2	Average Annual Asheville Combined Cycle O&M - NC Retail Per Public Staff	$2,169	2/
3	Adjustment to Asheville CC O&M expense (L2 - L1)	($3,918)	
	Rate Base Impact		
4	Asheville CC Inventory per Company	$3,735	3/
5	Asheville CC inventory per Public Staff	2,873	2/
6	Adjustment to Asheville Inventory (L5 - L4)	($862)	
7	Regulatory Asset for Asheville CCs as of Sep 1, 2020 per Company	$23,899	4/
8	Regulatory Asset for Asheville CCs as of Sep 1, 2020 per Public Staff	0	5/
9	Adjustment to Asheville CC Regulatory Asset (L7 - L8)	($23,899)	
10	Accumulated deferred income taxes related to he regulatory asset per Company	($5,537)	6/
11	Accumulated deferred income taxes related to he regulatory asset per Public Staff	0	5/
12	Adjustment to accumulated deferred income taxes	$5,537	
13	Adjustment to rate base for regulatory asset for Asheville CC (L6 + L9 + L12)	($19,224)	

1/ NCUC Form E-1, Item No. 10, NC-3401, Line 2, adjusted to SWPA.
2/ Per Public Staff witness Dustin Metz, adjusted to reflect 83% of the Asheville CC that is in service at 12/31/19.
3/ NCUC Form E-1, Item No. 10, NC-3401, Line 16, adjusted to SWPA.
4/ NCUC Form E-1, Item No. 10, NC-3401, Line 21, updated to December 31, 2019 and adjusted to SWPA.
5/ Public Staff removed he regulatory asset since the annuity method was used for determining the amortization.
6/ NCUC Form E-1, Item No. 10, NC-3401, Line 24, updated to December 31, 2017 and adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO ASHEVILLE COMBINED CYCLE DEFERRAL
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1 (t)(1)

Line No.	Item	Amount	
	Annuity Factor		
1	Amortization period recommended by Public Staff in years	5	1/
2	Payment per period	1	
3	After tax rate of return (L18)	6.0790%	
4	Present value of 1 dollar over number of years with 1 payment per year	4.2033	
5	1 plus (interest rate divided by two)	1.0304	
6	Annuity factor (L4 x L5)	4.3311	
7	Deferred costs per Public Staff	$35,169	2/
8	Annuity factor per Public Staff (L6)	4.3311	
9	Annual levelized amortization expense per Public Staff (L7 / L8)	$8,120	
10	Annual amortization expense per Company	13,433	3/
11	Adjustment to Asheville CC deferral amortization expense (L9 - L10)	($5,313)	

Line No.	Item	Capital Structure (a)	Cost Rates (b)	Overall Rate of Return 8/ (c)	Net of Tax Rate (d)
	After Tax Rate of Return				
12	Long-term debt	50.00% 4/	4.110% 6/	2.055%	1 579% 9/
13	Common equity	50.00% 5/	9.000% 7/	4.500%	4 500% 10/
14	Total	100.00%		6.555%	6 079%

1/ Rider period recommended by Public Staff.
2/ Dorgan Exhibit 1, Schedule 3-1(t)(2), Column (j), Line 22 plus Dorgan Exhibit 1, Schedule 3-1(t)(3), Column (j), Line 22.
3/ NCUC Form E-1, tem No. 10, NC-3401, Line 7 adjusted to SWPA.
4/ Dorgan Exhibit 1, Schedule 4, Line 1, Column (a).
5/ Dorgan Exhibit 1, Schedule 4, Line 2, Column (a).
6/ Dorgan Exhibit 1, Schedule 4, Line 1, Column (g).
7/ Dorgan Exhibit 1, Schedule 4, Line 2, Column (g).
8/ Column (a) multiplied by Column (b).
9/ Column (c) multiplied by (1 minus combined income tax rate of 23.1693%).
10/ Amount from Column (c).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF DEFERRED COSTS FOR ASHEVILLE COMBINED CYCLE - PRODUCTION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(t)(2)

Line No.	Item		December 2019	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	Totals 8/
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Production Plant placed into service - NC Retail	1/	302,260	351,195	467,718	467,718	$467,718	$467,718	$467,718	$467,718	$467,718	$467,718
2	ADIT balance	1/	(28,013)	(32,548)	(43,347)	(43,347)	(43,347)	(43,347)	(43,347)	(43,347)	(43,347)	(43,347)
3	Average inventory balance	1/	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735
4	Accumulated Depreciation	1/	0	(1,035)	(2,238)	(3,840)	(5,442)	(7,044)	(8,646)	(10,248)	(11,850)	(11,850)
5	Remove CWIP in Rate Base	1/	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)
6	Rate base balance for return (L3 + L4 + L5)		175,053	218,417	322,939	321,337	319,735	318,133	316,531	314,929	313,327	313,327
7	Pre-tax cost of capital rate	2/	8.6444%	8 6444%	8.6444%	8.6444%	8.6444%	8.6444%	8 6444%	8.6444%	8.6444%	
8	Deferred monthly cost of capital (L6 x L7/12)	3/	163	1,573	2,326	2,315	2,303	2,292	2,280	2,269	2,257	17,778
9	Plant balance (L3)		$0	302,260	351,195	467,718	467,718	467,718	467,718	467,718	467,718	
10	Annual depreciation rate	4/	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%	
11	Deferred monthly depreciation expense (L9 x L10/12)		0	1,035	1,203	1,602	1,602	1,602	1,602	1,602	1,602	11,850
12	Deferred O&M expense	5/	28	218	218	218	218	218	218	218	218	1,770
13	Plant balance (L3)		$302,260	$351,195	$467,718	$467,718	$467,718	$467,718	$467,718	$467,718	$467,718	
14	Annual Property tax rate	6/	0.3626%	0 3626%	0.3626%	0.3626%	0.3626%	0.3626%	0 3626%	0.3626%	0.3626%	
15	Deferred monthly property tax expense (L13 x L14/12)		12	106	141	141	141	141	141	141	141	1,105
16	Cumulative deferred costs (L8 + L11+L12+L15)		203	2,932	3,888	4,276	4,264	4,253	4,241	4,230	4,218	
17	Composite income tax rate	7/	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	
18	Income tax on deferred expenses (-L16 x L17)		(47)	(679)	(901)	(991)	(988)	(985)	(983)	(980)	(977)	
19	Deferred costs, net of tax (L16 + L18)		156	2,253	2,987	3,285	3,276	3,268	3,258	3,250	3,241	
20	Pre-tax cost of capital rate (L7)	2/	8.644%	8.644%	8.644%	8.644%	8 644%	8.644%	8.644%	8.644%	8.644%	
21	Pre-tax return on monthly deferred expenses (L19 x L20)		13	195	258	284	283	282	282	281	280	2,159
22	Total deferred costs per Public Staff (L8 + L11 + L12 + L15 + L21)		$217	$3,126	$4,146	$4,560	$4,547	$4,535	$4,522	$4,511	$4,498	$34,662

1/ NCUC Form E-1, Item No. 10, NC-3403, updated to December31, 2019, Columns (d) through (n).
2/ Pre-tax costs of capital per Order Granting General Rate Increase issued on February 23, 2018, in Docket No. E-2, Sub 1142.
3/ Monthly deferred cost of capital multiplied by 4 days, divided by 31 days.
4/ NCUC Form E-1, Item No. 10, NC-3403, Page 1 of 2, Column (p), Line 30.
5/ Per Public Staff witness Metz. First month multiplied by 4 days, divided by 31 days.
6/ NCUC Form E-1, Item No. 10, NC-3403, Page 1 of 2, Column (p), Line 31.
7/ Dorgan Exhibit 1, Schedule 1-3, Line 8, Column (a).
8/ Sum of Columns (a) through (d).

I/A

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF DEFERRED COSTS FOR ASHEVILLE COMBINED CYCLE - TRANSMISSION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(t)(3)

Line No.	Item		December 2019	January 2020	February 2020		March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	Total 8/
			(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Transmission Plant placed into service	1/	$7,422	$7,422	$7,422		7,422	7,422	7,422	7,422	7,422	7,422	7,422
2	ADIT balance	1/	(67)	(67)	(67)		(67)	(67)	(67)	(67)	(67)	(67)	(67)
3	Average inventory balance	1/	0	0	0		0	0	0	0	0	0	-
4	Accumulated Depreciation	1/	0	(12)	(24)		(36)	(48)	(60)	(72)	(84)	(96)	(96)
5	Remove CWIP in Rate Base	1/	0	0	0		0	0	0	0	0	0	-
6	Rate base balance for return (L3 + L4 + L5)		7,355	7,343	7,331		7,319	7,307	7,295	7,283	7,271	7,259	$7,259
7	Monthly pre-tax cost of capital rate	2/	8.6444%	8 6444%	8.6444%	4/	8.6444%	8.6444%	8.6444%	8 6444%	8.6444%	8.6444%	
8	Deferred monthly cost of capital (L6 x L7/12)	3/	53	53	53		53	53	53	53	52	52	474
9	Plant balance (L3)		$0	7,422	7,422		7,422	7,422	7,422	7,422	7,422	7,422	
10	Annual depreciation rate	4/	1.90%	1.90%	1 90%	5/	1 90%	1.90%	1.90%	1.90%	1 90%	1 90%	
11	Deferred monthly depreciation expense (L9 x L10/12)		0	12	12		12	12	12	12	12	12	96
12	Deferred O&M expense	5/	0	0	0	6/	0	0	0	0	0	0	0
13	Plant balance (L3)		$7,422	$7,422	$7,422		$7,422	$7,422	$7,422	$7,422	$7,422	$7,422	
14	Annual Property tax rate	6/	0.3626%	0 3626%	0.3626%	7/	0.3626%	0.3626%	0.3626%	0 3626%	0.3626%	0.3626%	
15	Deferred monthly property tax expense (L13 x L14/12)		2	2	2		2	2	2	2	2	2	18
16	Cumulative deferred costs (L8 + L11+L12+L15)		55	67	67	8/	67	67	67	67	66	66	588
17	Composite income tax rate	7/	23.1693%	23.1693%	23.1693%	9/	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	
18	Income tax on deferred expenses (-L16 x L17)			(16)	(15)		(15)	(15)	(15)	(15)	(15)	(15)	(121)
19	Deferred costs, net of tax (L16 + L18)		55	51	52		52	52	52	52	51	51	
20	Pre-tax cost of capital rate (L7)	2/	8.644%	8.644%	8.644%		8.644%	8 644%	8.644%	8.644%	8.644%	8.644%	
21	Pre-tax return on monthly deferred expenses (L19 x L20)		5	4	4		4	4	4	4	4	4	40
22	Total deferred costs per Public Staff (L8 + L11 + L12 + L15 + L21)		$60	$55	$56		$56	$56	$56	$56	$56	$56	$507

1/ Smith Exhibit 1 and NCUC Form E-1, tem No. 10, NC-3404, Supplemental (C), December Update, Page 1 of 2, Columns (d) through (n).
2/ Pre-tax costs of capital per Order Granting General Rate Increase issued on February 23, 2018, in Docket No. E-2, Sub 1142.
3/ Monthly deferred cost of capital times 4 days, divided by 31 days.
4/ Smith Exhibit 1 and NCUC Form E-1, tem No. 10, NC-3404, Page 1 of 2, Column (p), Line 30.
5/ Per Public Staff witness Metz. First month multiplied by 4 days, divided by 31 days.
6/ Smith Exhibit 1 and NCUC Form E-1, tem No. 10, NC-3404, Page 1 of 2, Column (p), Line 31.
7/ Dorgan Exhibit 1, Schedule 1-3, Line 8, Column (a).
8/ Sum of Columns (a) through (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
NON-FUEL O&M DISPLACEMENT ADJUSTMENT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(u)

Line No.	Item	Amount	
1	Asheville Coal Plant generation MW Retired per Company	400	1/
2	Capacity Factor	36%	2/
3	Hours per year	8,760	
4	Total mWh for Asheville Coal generation (L1 x L2 x L3)	1,261,440	
5	Asheville CC generation mWh at December 31, 2019	480	3/
6	Capacity Factor	70%	4/
7	Hours per year	8,760	
8	Total mWh for Asheville CC generation at December 31, 2019 (L5 x L6 x L7)	2,943,360	
9	Additional mWH generation added - system (L8 - L4)	1,681,920	
10	NC retail allocation percentage	60.2976%	5/
11	NC retail additional mWh generation added	1,014,157	
12	Non-fuel energy-related expense factor used by Public Staff	0.00582786	6/
13	NC retail displacement adjustment (L11 x -L12)	$ (5,910)	

1/ Based on DEP Application.
2/ 2018 test year capacity factor provided by Public Staff witness Metz.
3/ Based on Asheville CC MW closed to plant at December 31, 2019.
4/ Based on discussions with Public Staff witness Metz.
5/ NC retail allocation factor: SWPA_RB_PLT_O_PR
6/ Dorgan Exhibit 1, Schedule 3-1(b)(3), Line 24. divided by 1,000

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO COMPANY'S INFLATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(v)

Line No.	Item	Amount	
1	Total non-labor O&M expense to be adjusted per Company	$208,360	1/
2	Public Staff adjustment to variable O&M expenses for changes in customer growth	(4,079)	2/
3	Public Staff adjustment to aviation expense - Salary & Wage component	(201)	3/
4	Public Staff adjustment to outside services	(146)	4/
5	Public Staff adjustment to sponsorships and donations	(36)	5/
6	Public Staff adjustment to lobbying	(1,538)	6/
7	Public Staff adjustment to Board of Directors expenses	(1,270)	7/
8	Total adjusted O&M subject to inflation (Sum of L1 thru L7)	$201,090	
9	Inflation percentage based on December 31, 2019 update	1.66%	8/
10	Public Staff inflation adjustment (L7 x L8)	$3,338	
11	Company adjustment	1,333	9/
12	Public Staff adjustment to inflation (L9 - L10)	$2,005	

1/ NCUC Form E-1, Item No. 10, NC-1201, Line 27, NC Retail Column.
2/ Dorgan Exhibit 1, Schedule 3-1(b)(1), Line 14.
3/ Dorgan Exhibit 1, Schedule 3-1(j), Line 9.
4/ Dorgan Exhibit 1, Schedule 3-1(k), Line 6.
5/ Dorgan Exhibit 1, Schedule 3-1(n), Line 6.
6/ Dorgan Exhibit 1, Schedule 3-1(o), Line 7.
7/ Dorgan Exhibit 1, Schedule 3-1(p), Line 15.
8/ Dorgan Exhibit 1, Schedule 3-1(v)(1), Line 4, Column (e).
9/ NCUC Form E-1, Item No. 10, NC-1201, Line 29, NC Retail Column.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF INFLATION RATE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(v)(1)

Line No.	Item	CPI (a)		PPI Finished Goods Less Food & Energy (b)		PPI Processed Materials Less Food & Energy (c)		PPI Average (d)		Inflation Rate (e)	
1	December 2019	257.0	1/	208.9	1/	199.2	1/				
2	Thirteen month average for test year	250.8	2/	203.2	2/	201.4	2/				
3	Increase (decrease) from average to December 2019 (L1 - L2)	6.2		5.7		(2.2)					
4	Percentage increase (decrease)	2.46%	3/	2.81%	3/	-1.09%	3/	0.86%	4/	1.66%	5/

1/ Per Company response to DR1-7, updated as of December 31, 2019.
2/ NCUC Form E-1, Item No. 10, NC-1202, Line 15.
3/ Line 3 divided by Line 2.
4/ Average of percentage increases (decreases) in Columns (b) and (c).
5/ Average of CPI percentage increase (decrease) and PPI average percentage increase (decrease) in Columns (a) and (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
INTEREST SYNCHRONIZATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(w)

Line No.	Item	Amount	
1	Public Staff original cost rate base	$10,100,532	1/
2	Public Staff long term debt ratio	50.000%	2/
3	Public Staff embedded cost of debt	4.110%	3/
4	Public Staff interest expense income tax deduction (L1 x L2 x L3)	$207,566	
5	Company interest expense income tax deduction	210,604	4/
6	Adjustment to interest expense (L4 - L5)	($3,038)	
7	Composite tax rate	23.1693%	5/
8	Adjustment to income taxes (-L6 x L7)	$704	

1/ Dorgan Exhibit 1, Schedule 2, Line 16, Column (c).
2/ Dorgan Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Dorgan Exhibit 1, Schedule 4, Line 1, Column (c).
4/ Dorgan Exhibit 1, Schedule 3-1(w)(1), Line 4.
5/ Dorgan Exhibit 1, Schedule 1-3, Line 8.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF COMPANY'S INTEREST SYNCHRONIZATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(w)(1)

Line No.	Item	Amount	
1	NC retail rate base per Company	$10,785,574	1/
2	Long tern debt ratio per Company	47.000%	2/
3	Long term debt cost rate per Company	4.155%	2/
4	Interest tax deduction per Company (L1 x L2 x L3)	$210,604	

1/ Dorgan Exhibit 1, Schedule 2, Line 16, Column (a).
2/ Smith Exhibit 1, Page 2, Line 1, Column 4.
3/ Smith Exhibit 1.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
RETURN ON EQUITY AND ORIGINAL COST RATE BASE BEFORE AND AFTER PUBLIC STAFF PROPOSED INCREASE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 4

			Before Public Staff Proposed Increase				After Public Staff Proposed Increase			
Line No.	Item	Capitalization Ra io	NC Retail Rate Base	Embedded Cost or Return	Weighted Cost or Return	Net Operating Income	NC Retail Rate Base	Embedded Cost or Return	Weighted Cost or Return	Net Operating Income
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Long-term debt	50 000% 1/	$5,050,266 2/	4.11% 1/	2.06% 5/	$207,566 6/	$5,055,072 9/	4.11% 1/	2.0550% 11/	$207,763 12/
2	Common equity	50 000% 1/	5,050 266 2/	7.36% 4/	3.68% 5/	371,492 7/	5,055,072 9/	9.00% 1/	4.500% 11/	454,956 12/
3	Total (L1 + L2)	100 000%	$10,100,532 3/		5.74%	$579,058 8/	$10,110,143 10/		6.5550%	$662,719

1/ Per Public Staff witness Woolridge.
2/ Column (b), Line 3 multiplied by Column (a), Lines 1 and 2
3/ Dorgan Exhibit 1, Schedule 2, Line 16, Column (c).
4/ Line 2, Column (e) divided by Line 2, Column (b).
5/ Column (a) multiplied by Column (c).
6/ Line 1, Column (b) multiplied by Line1, Column (c).
7/ Line 3, Column (e) minus Line 1, Column (e).
8/ Dorgan Exhibit 1, Schedule 3, Line 17, Column (c).
9/ Line 3, Column (f) multiplied by Column (a), Lines 1 and 2
10/ Dorgan Exhibit 1, Schedule 2, Line 16, Column (e).
11/ Column (a) multiplied by Column (g).
12/ Column (f) multiplied by Column (g).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF PUBLIC STAFF'S ADDITIONAL GROSS REVENUE REQUIREMENT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 5

Line No.	Item	Debt (a)		Equity (b)		Total 7/ (c)
	Calculation of additional gross revenue requirement					
1	Required net operating income	$207,763	1/	454,956	4/	$662,719
2	Net operating income before proposed increase	207,566	2/	371,492	5/	579,058
3	Additional net operating income requirement (L1 - L2)	$197		$83,464		$83,661
4	Retention factor	0.9963091	3/	0.7654709	6/	
5	Additional revenue requirement (L5 - L6)	$198		$109,036		$109,234

1/ Dorgan Exhibit 1, Schedule 4, Line 1, Column (i).
2/ Dorgan Exhibit 1, Schedule 4, Line 1, Column (e).
3/ Dorgan Exhibit 1, Schedule 1-2, Line 10.
4/ Dorgan Exhibit 1, Schedule 4, Line 2, Column (i).
5/ Dorgan Exhibit 1, Schedule 4, Line 2, Column (e).
6/ Dorgan Exhibit 1, Schedule 1-2, Line 14.
7/ Column (a) plus Column (b).
8/ Smith Exhibit 2 Page 1, Line 5.

INDEX TO DORGAN EXHIBIT 2

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF LEVELIZED EDIT RIDER CREDIT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 2
Schedule 1

Line No.	Item	Year 1 Revenue Requirement (a)		Year 2 Revenue Requirement (b)		Year 3 Revenue Requirement (c)		Year 4 Revenue Requirement (d)		Year 5 Revenue Requirement (e)		Total Revenue Requirement (f)	
1	Total NC retail regulatory liability to be amortized	($406,254)	1/	($406,254)	1/	($406,254)	1/	($406,254)	1/	($406,254)	1/		
2	Annuity factor	4.3311	2/	4.3311	2/	4.3311	2/	4.3311	2/	4.3311	2/		
3	Levelized rider EDIT regulatory liability (L1 / L2)	(93,799)		(93,799)		(93,799)		(93,799)		(93,799)		($468,995)	5/
4	One minus composite income tax rate	76.8307%	3/	76.8307%	3/	76.8307%	3/	76.8307%	3/	76.8307%	3/	76.8307%	
5	Net operating income effect (L3 x L4)	(72,066)		(72,066)		(72,066)		(72,066)		(72,066)		(360,332)	
6	Retention factor	0.7654709	4/	0.7654709	4/	0.7654709	4/	0.7654709	4/	0.7654709	4/	0.7654709	
7	Levelized rider EDIT credit (L5 / L6)	($94,146)		($94,146)		($94,146)		($94,146)		($94,146)		($470,732)	

1/ Smith Exh bit 4, Page 1, Columns (b) and (c), Line 10.
2/ Dorgan Exhibit 2, Schedule 1(a), Line 6.
3/ One minus composite income tax rate of 23.1693%.
4/ Dorgan Exhibit 1, Schedule 1-2, Line 14, Column (d).
5/ Column (a) plus Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ANNUITY FACTOR FOR EDIT LIABILITY RIDER
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 2
Schedule 1(a)

Line No.	Item	Amount	
	Annuity Factor		
1	Number of years	5	1/
2	Payment per period	1	
3	After tax rate of return (L9)	6.079%	
4	Present value of 1 dollar over "number of years" with with 1 payment per year	4.2033	
5	1 plus (interest rate divided by two)	1.0304	
6	Annuity factor (L4 x L5)	4.3311	

Line No.		Capital Structure (a)		Cost Rates (b)		Overall Rate of Return (c)	6/	Net of Tax Rate (d)	
	After Tax Rate of Return								
7	Long-term debt	50.00%	2/	4.110%	4/	2.055%		1.579%	7/
8	Common equity	50.00%	3/	9.000%	5/	4.500%		4.500%	8/
9	Total	100.00%				6.555%		6.079%	

1/ Rider period recommended by Public Staff.
2/ Dorgan Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Dorgan Exhibit 1, Schedule 4, Line 2, Column (a).
4/ Dorgan Exhibit 1, Schedule 4, Line 1, Column (g).
5/ Dorgan Exhibit 1, Schedule 4, Line 2, Column (g).
6/ Column (a) multiplied by Column (b).
7/ Column (c) multiplied by (One minus combined income tax rate of 23.1693%).
8/ Amount from Column (c).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF LEVELIZED FEDERAL PROVISIONAL EDIT RIDER CREDIT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 2
Schedule 2

Line No.	Item	Year 1 Revenue Requirement (a)		Total Revenue Requirement (b)
1	Total NC retail regulatory liability to be amortized	($110,315)	1/	
2	Annuity factor	0.9714	2/	
3	Levelized rider EDIT regulatory liability (L1 / L2)	(113,563)		($113,563)
4	One minus composite income tax rate	76.8307%	3/	76.8307%
5	Net operating income effect (L3 x L4)	(87,251)		(87,251)
6	Retention factor	0.7654709	4/	0.7654709
7	Levelized rider EDIT credit (L5 / L6)	($113,983)		($113,983)

1/ Smith Exhibit 4, Page 1, Column (e), Line 8.
2/ Dorgan Exhibit 2, Schedule 2(a), Line 6.
3/ One minus composite income tax rate of 23.1693%.
4/ Dorgan Exhibit 1, Schedule 1-2, Line 14, Column (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ANNUITY FACTOR FOR EDIT LIABILITY RIDER
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 2
Schedule 2(a)

Line No.	Item	Amount	
	Annuity Factor		
1	Number of years	1	1/
2	Payment per period	1	
3	After tax rate of return (L9)	6.079%	
4	Present value of 1 dollar over "number of years" with with 1 payment per year	0.9427	
5	One plus (interest rate divided by two)	1.0304	
6	Annuity factor (L4 x L5)	0.9714	

Line No.	Item	Capital Structure (a)		Cost Rates (b)		Overall Rate of Return 6/ (c)	Net of Tax Rate (d)	
	After Tax Rate of Return							
7	Long-term debt	50.00%	2/	4.110%	4/	2.055%	1.579%	7/
8	Common equity	50.00%	3/	9.000%	5/	4.500%	4.500%	8/
9	Total	100.00%				6.555%	6.079%	

1/ Rider period recommended by Public Staff.
2/ Dorgan Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Dorgan Exhibit 1, Schedule 4, Line 2, Column (a).
4/ Dorgan Exhibit 1, Schedule 4, Line 1, Column (g).
5/ Dorgan Exhibit 1, Schedule 4, Line 2, Column (g).
6/ Column (a) multiplied by Column (b).
7/ Column (c) multiplied by (One minus composite income tax rate of 23.1693%).
8/ Amount from Column (c).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF LEVELIZED STATE EDIT RIDER CREDIT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 2
Schedule 3

Line No.	Item	Year 1 Revenue Requirement (a)		Total Revenue Requirement (b)
1	Total NC retail regulatory liability to be amortized	($23,726)	1/	
2	Annuity factor	0.9714	2/	
3	Levelized rider EDIT regulatory liability (L1 / L2)	(24,425)		($24,425)
4	One minus composite income tax rate	76.8307%	3/	76.8307%
5	Net operating income effect (L3 x L4)	(18,766)		(18,766)
6	Retention factor	0.7654709	4/	0.7654709
7	Levelized rider N.C. State EDIT credit (L5 / L6)	($24,516)		($24,516)

1/ Smith Exhibit 4, Page 1, Column (d), Line 8.
2/ Dorgan Exhibit 2, Schedule 2(a), Line 6.
3/ One minus composite income tax rate of 23.1693%.
4/ Dorgan Exhibit 1, Schedule 1-2, Line 14, Column (d).

INDEX TO DORGAN EXHIBIT 3

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
COMPANY RATE BASE, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 3
Schedule 1-1

		North Carolina Retail Operations		
Line No.	Description	Company SWPA Per Books 1/	Company SWPA Proforma Accounting Adjustments 2/	SWPA Reallocated By Public Staff 3/
		(a)	(b)	(c)
1	Electric plant in service	$18,662,205	$ 580,500	$19,242,705
2	Accumulated depreciation and amortization	(7,983,917)	(101,828)	(8,085,745)
3	Net electric plant (L1 + L2)	$10,678,288	$478,672	$11,156,960
4	Materials and supplies	750,939	(150,623)	600,316
5	Working capital investment	(376,636)	885,931	509,295
6	Accumulated deferred taxes	(1,318,934)	(188,064)	(1,506,999)
7	Operating reserves	(54,448)	-	(54,448)
8	Construction work in progress	102,930	(102,930)	(0)
9	Total Original Cost Rate Base (Sum of L3 through L8)	$9,782,137	$922,987	$10,705,124

1/ Per cost of service study recommended by Public Staff witness McLawhorn.
2/ Dorgan Exhibit III, Schedule 1-1, Line 36.
3/ Column (a) plus Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
COMPANY ADJUSTMENTS TO RATE BASE, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 3
Schedule 1 1

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)
1		Annualize retail revenues for current rates	-	-	-	-	-	-	-	-
2		Update fuel costs to proposed rate	-	-	-	-	-	-	-	-
3	*	Normalize for weather	-	-	-	-	-	-	-	-
4	*	Annualize revenues for customer growth	-	-	-	-	-	-	-	-
5		Eliminate unbilled revenues	-	-	-	-	-	-	-	-
6		Adjust for costs recovered through non-fuel riders	(969,419)	157,523	(157,051)	(150,987)	89,762	-	-	(1,030,172)
7		Adjust O&M for executive compensation	-	-	-	-	-	-	-	-
8		Annualize depreciation on year end plant balances	-	-	-	-	-	-	-	-
9		Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-
10	*	Adjust for post test year additions to plant in service	1,833,852	(380,296)	-	(1,458)	(30,983)	-	(102,930)	1,318,186
11	*	Amortize deferred environmental costs	-	-	-	423,532	(98,129)	-	-	325,403
12		Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-
13	*	Normalize O&M labor expenses	-	-	-	-	-	-	-	-
14		Update benefits costs	-	-	-	-	-	-	-	-
15	*	Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-
16	*	Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051
17		Adjust aviation expenses	-	-	-	-	-	-	-	-
18		Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)
19	*	Adjust for Merger Related Costs	-	342	-	-	-	-	-	342
20	*	Amortize Severance Costs	-	-	-	23,186	(5,372)	-	-	17,814
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
COMPANY ADJUSTMENTS TO RATE BASE, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-
23	*	Adjust cash working capital	-	-	-	(27,013)	-	-	-	(27,013)
24		Adjust coal inventory	-	-	9,641	-	-	-	-	9,641
25	*	Adjust for credit card fees	-	-	-	-	-	-	-	-
26		Adjust Depreciation for new rates	-	(87,779)	-	-	-	-	-	(87,779)
27		Adjust vegetation management expenses	-	-	-	-	-	-	-	-
28		Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-
29	*	Update deferred balance and amortize storm costs	-	-	-	607,773	(140,817)	-	-	466,956
30		Adjust other revenue	-	-	-	-	-	-	-	-
31		Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-
32	*	Reflect retirement of Asheville Steam Generating Plant	(283,933)	208,382	(6,949)	65,212	(15,109)	-	-	(32,396)
33		Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	3,735	26,866	(6,225)	-	-	24,377
35		Adjust Purchased Power	-	-	-	-	-	-	-	-
36		Total adjustments	$ 580,500	$ (101,828)	$ (150,623)	$ 885,931	$ (188,064)	$ -	$ (102,930)	$ 922,987

Notes:
* Identification required by NCUC Rule R1-17(b)

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
COMPANY NET OPERATING INCOME, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 3
Schedule 2

		North Carolina Retail Operations		
Line No.	Description	Company SWPA Per Books 1/ (a)	Company SWPA Proforma Accounting Adjustments 2/ (b)	SWPA Reallocated By Public Staff 3/ (c)
1	Electric operating revenue	$ 3,657,316	$ (318,107)	$ 3,339,209
	Electric operating expenses:			
	Operation and maintenance:			
2	Fuel used in electric generation	881,642	(46,419)	835,224
3	Purchased power	158,032	(1,944)	156,088
4	Other operation and maintenance expense	1,047,158	(175,567)	871,591
5	Depreciation and amortization	665,546	299,031	964,577
6	General taxes	101,487	2,027	103,514
7	Interest on customer deposits	7,971	-	7,971
8	Net income taxes	115,441	(75,208)	40,234
9	Amortization of investment tax credit	(2,111)	(1,468)	(3,580)
10	Total electric operating expenses (Sum of L2 through L9)	2,975,166	453	2,975,618
11	Operating income (L1 minus L10)	$ 682,151	$ (318,560)	$ 363,590

1/ Per cost of service study recommended by Public Staff witness McLawhorn.
2/ Dorgan Exhibit III, Schedule 2-1, Line 36.
3/ Column (a) plus Column (b).

I/A

DUKE ENERGY PROGRESS, LLC
Docket No. E 2, Sub 1219
North Carolina Retail Operations
COMPANY ADJUSTMENTS TO NET OPERATING INCOME, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 3
Schedule 2 1
Page 1 of 2

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	Income Taxes (at Composite Rate of 23.1693005%) (Col. 7)	Amortization of ITC (Col. 8)	Operating Income
1		Annualize retail revenues for current rates	(225,760)	-	-	(833)	-	-	(52,114)	-	(172,813)
2		Update fuel costs to proposed rate	-	(12,574)	-	-	(1,666)	-	3,299	-	10,941
3	*	Normalize for weather	(77,392)	(18,180)	-	(286)	-	-	(13,653)	-	(45,273)
4	*	Annualize revenues for customer growth	5,182	2,857	-	19	-	-	534	-	1,771
5		Eliminate unb lled revenues	11,826	-	-	-	-	-	2,740	-	9,086
6		Adjust for costs recovered through non-fuel riders	(27,808)	(18,522)	-	(135,418)	(58,100)	(6,392)	62,909	-	127,714
7		Adjust O&M for executive compensation	-	-	-	(2,387)	-	-	553	-	1,834
8		Annualize depreciation on year end plant balances	-	-	-	-	41,597	-	(9,638)	(1,468)	(30,491)
9		Annualize property taxes on year end plant balances	-	-	-	-	-	4,032	(934)	-	(3,098)
10	*	Adjust for post test year additions to plant in service	-	-	-	-	69,927	6,557	(17,721)	-	(58,764)
11	*	Amortize deferred environmental costs	-	-	-	-	105,883	-	(24,532)	-	(81,351)
12		Annualize O&M non-labor expenses	-	-	-	2,123	-	-	(492)	-	(1,631)
13	*	Normalize O&M labor expenses	-	-	-	(18,424)		(1,084)	4,520	-	14,988
14		Update benef ts costs	-	-	-	(3,045)	-	-	706	-	2,340
15	*	Levelize nuclear refueling outage costs	-	-	-	(6,232)	-	-	1,444	-	4,788
16	*	Amortize rate case costs	-	-	-	701	-	-	(162)	-	(539)
17		Adjust aviation expenses	-	-	-	(1,445)	-	(18)	339	-	1,124
18		Adjust for approved regulatory assets and iabilities	-	-	-	1,603	(3,489)	5	436	-	1,445
19	*	Adjust for Merger Related Costs	-	-	-	(4,021)	(170)	(53)	983	-	3,260
20	*	Amortize Severance Costs	-	-	-	(23,254)	-	-	5,388	-	17,867
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	(2,228)	-	2,228

DUKE ENERGY PROGRESS, LLC
Docket No. E 2, Sub 1219
North Carolina Retail Operations
COMPANY ADJUSTMENTS TO NET OPERATING INCOME, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 3
Schedule 2 1
Page 2 of 2

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	Income Taxes (at Composite Rate of 23.1693005%) (Col. 7)	Amortization of ITC (Col. 8)	Operating Income
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	(272)	-	272
23	*	Adjust cash working capital	-	-	-	-	-	-	122	-	(122)
24		Adjust coal inventory	-	-	-	-	-	-	-	-	-
25	*	Adjust for credit card fees	-	-	-	5,197	-	-	(1,204)	-	(3,993)
26		Adjust Depreciation for new rates	-	-	-	-	88,642	-	(20,538)	-	(68,104)
27		Adjust vegetation management expenses	-	-	-	5,746	-	-	(1,331)	-	(4,415)
28		Adjust reserve for end of life nuclear costs	-	-	-	-	(260)	-	60	-	200
29	*	Update deferred balance and amortize storm costs	-	-	-	-	43,412	-	(10,058)	-	(33,354)
30		Adjust other revenue	(4,155)	-	-	(5)	-	-	(962)	-	(3,188)
31		Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	54	-	180
32	*	Reflect retirement of Ashevi le Steam Generating Plant	-	-	-	(6,397)	(179)	(1,021)	1,760	-	5,837
33		Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	(1,144)	-	(3,794)
34	*	Amortize deferred balance Ashevi le Combined Cycle	-	-	-	6,087	13,433	-	(4,523)	-	(14,997)
35		Adjust Purchased Power	-	-	(1,944)	-	-	-	450	-	1,493
36		Total adjustments	$ (318 107)	$ (46 419)	$ (1 944)	$ (175 567)	$ 299 031	$ 2 027	$ (75 208)	$ (1 468)	$ (318 560)

Notes

INDEX TO DORGAN SUPPLEMENTAL EXHIBIT 1

INDEX TO DORGAN SUPPLEMENTAL EXHIBIT 1

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
REVENUE IMPACT OF PUBLIC STAFF ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 1

Line No.		Amount	
1	Revenue requirement increase per Company application, base rates	$ 585,961	1/
2	Revenue impact of Company updates/supplemental filing	(51,617)	
3	**Revenue requirement increase per Company after updates/supplemental filing**	**$ 534,344**	
4	Revenue impact of Public Staff adjustments: 2/		
5	Change in equity ratio from 53.00% to 50.00% equity	($29,654)	
6	Change in debt cost rate from 4.155% to 4.110%	(2,381)	
7	Change in return on equity from 10.30% to 9.00%	(90,390)	
8	Adjust for cost of service reallocations - SWP&A	(10,770)	
9	Update plant and accumulated depreciation to February 29, 2020	(160)	
10	Update revenues, customer growth, and weather to February 29, 2020	(7,428)	
11	Adjust payment card fees	(95)	
12	Remove Unprotected Federal, State EDIT, and deferred Federal from base rates for treatment as a rider	42,729	3/
13	Adjust for flowback of Protected Federal EDIT due to Tax Cuts and Jobs Act	(28,796)	
14	Adjust aviation expenses	(409)	
15	Adjust executive compensation	(161)	
16	Adjust salaries & wage expense	-	
17	Adjust outside services	(146)	
18	Adjust rate case expense	(357)	
19	Adjust to normalize storm costs	9,334	
20	Adjust to remove storm deferral	(83,121)	
21	Adjust for severance costs	(5,668)	
22	Adjust depreciation rates	(39,539)	
23	Adjust incentives	(14,705)	
24	Adjust deferred environmental costs	(98,936)	
25	Adjust deferred non-ARO environmental costs	(3,732)	
26	Adjust Asheville CC Plant in Service	(4,892)	
27	Adjust Asheville CC deferral	(2,840)	
28	Adjust W. Asheville Vanderbilt 115kV Project	(398)	
29	Adjust Asheville production displacement	(8,095)	
30	Adjust coal inventory	-	
31	Adjust EOL nuclear materials & supplies reserve expense	(1,813)	
32	Adjust charitable contributions, corporate sponsorships, and corporate donations	(37)	
33	Adjust lobbying expense	(1,544)	
34	Adjust Board of Directors expense	(1,275)	
35	Adjust inflation to February 29, 2020	2,810	
36	Adjust nuclear decommissioning expense	(16,599)	
37	Adjust to remove CertainTeed payment obligation	(4,958)	
38	Adjust cash working capital under present rates	3,959	
39	Adjust cash working capital under proposed rates	(5,265)	
40	Rounding	2	
41	Total revenue impact of Public Staff adjustments	($405,330)	
42	**Public Staff recommended increase (decrease) in base rate revenue requirement**	**$ 129,014**	4/
43	Public Staff recommended increase (decrease) in base rate revenue requirement (L42)	$ 129,014	
44	Annual Federal provisional EDIT Rider recommended by Public Staff for one year period	(113,983)	3/
45	Annual State EDIT Rider recommended by Public Staff for one year period	(24,795)	3/
46	Annual Federal unprotected EDIT Rider recommended by Public Staff for five year period	(93,566)	3/
47	Regulatory asset/liability rider for one year period recommended	(2,091)	5/
48	Public Staff recommended change in revenue requirement for first year (Sum of L43 through L47)	$ (105,421)	
49	Public Staff recommended change in revenue requirement for years 2 through 5 (L43 + L46)	$ 35,448	

1/ Smith Supplemental Supplemental Exhibit 1, Page 2, Line 8 (Prior to Company's rider-related revenue adjustment).

2/ Calculated based on Dorgan Supplemental Exhibit 1, Schedules 2, 3, 4, 5, and backup schedules.

3/ The Public Staff is recommending that the Company's EDIT regulatory liabilities be refunded through one and five year riders. As a result, the Public Staff has removed the amounts included by the Company in its revenue requirement calculations associated with EDIT refunds, and instead has calculated separate riders that will credit customers for EDIT refunds over the corresponding periods. The calculation of all annual EDIT riders is shown on Dorgan Supplemental Exhibit 2.

4/ Dorgan Supplemental Exhibit 1, Schedule 5, Line 5.

5/ Smith Supplemental Supplemental Exhibit 5.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUPPORT FOR RECONCILIATION SCHEDULE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 1-1

Line No.	Item	Rate Base Impact 1/	Income Statement Impact 2/	Total Revenue Impact 3/
		(a)	(b)	(c)
1	Update plant and accumulated depreciation to February 29, 2020	$0	($160)	($160)
2	Adjust unprotected EDIT for refund as a series of riders	42,729	-	42,729
3	Adjust for flowback of Protected EDIT	1,864	(30,660)	(28,796)
4	Adjust for severance costs	(1,321)	(4,347)	(5,668)
5	Adjust depreciation rates	3,397	(42,936)	(39,539)
6	Adjust for cost of service reallocations - SWP&A	(5,463)	(5,307)	(10,770)
7	Adjust deferred environmental costs	(21,483)	(77,453)	(98,936)
8	Adjust deferred non-ARO environmental costs	241	(3,973)	(3,732)
9	Adjust Asheville CC Plant in Service costs	(1,396)	(3,496)	(4,892)
10	Adjust Asheville CC deferral	-	(2,840)	(2,840)
11	Remove Storm Deferral	(38,161)	(44,960)	(83,121)
12	Adjust rate case expense	(163)	(194)	(357)

1/ Dorgan Supplemental Exhibit 1, Schedule 2-1, Line 15.
2/ Dorgan Supplemental Exhibit 1, Schedule 3-1, Line 18.
3/ Column (a) plus Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF GROSS REVENUE EFFECT FACTORS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 1-2

Line No.	Item		Capital Structure (a)		Cost Rates (b)		Retention Factor (c)		Gross Revenue Effect (d)	
1	**Rate Base Factor**									
2	Long-term debt		50.000%	1/	4.110%	1/	0.9963091	2/	0.0206261	4/
3	Common equity		50.000%	1/	9.00%	1/	0.7654709	3/	0.0587873	4/
4	Total (Sum of Lines 2 and 3)		100.000%						0.0794134	
									Amount	
5	**Net Income Factor**									
6	Total revenue								1.0000000	
7	Uncollectibles								0.0023940	5/
8	Balance (L6 - L7)								0.9976060	
9	Regulatory fee (L8 x 0.130%)	6/							0.0012969	
10	Balance (L8 - L9)								0.9963091	
11	State income tax (L10 x 2.7460%)	7/							0.0273586	
12	Balance (L10 - L11)								0.9689505	
13	Federal income tax (L12 x 21%)	8/							0.2034796	
14	Retention factor (L12 - L13)								0.7654709	

1/ Per Public Staff witness Woolridge.
2/ Line 10.
3/ Line 14.
4/ Column (a) multiplied by Column (b), divided by Column (c).
5/ NCUC Form E-1, Item No. 10, NC-0105, Line 3.
6/ Current NCUC regulatory fee rate effective.
7/ Dorgan Supplemental Exhibit 1, Schedule 1-3, Line 4, Column (a).
8/ Statutory rate.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF WEIGHTED STATE INCOME TAX RATE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 1-3

Line No.	Item	Total System		North Carolina		South Carolina	
		(a)		(b)		(c)	
1	**Weighted state income tax rate**						
2	Apportionment factor			84.6380%	2/	12.6000%	2/
3	State income tax rate			2.50%	3/	5.00%	3/
4	Weighted state income tax rate	2.7460%	1/	2.11595%	4/	0.63000%	4/
5	**Composite income tax rate**						
6	Weighted state income tax rate (L4)	2.7460%					
7	Federal income tax rate	21%	5/				
8	Composite income tax rate	23.1693%	6/				

1/ Sum of Columns (b) and (c).
2/ NCUC Form E-1, Item No. 10, NC-0104, Column (b), Lines 3 and 4.
3/ NCUC Form E-1, Item No. 10, NC-0104, Column (a), Lines 3 and 4.
4/ Line 2 times Line 3.
5/ Statutory rate.
6/ 1 minus ((1 minus Line 6) multiplied by (1 minus Line 7)).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ORIGINAL COST RATE BASE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2

Line No.	Item	Under Present Rates: NC Retail, as Adjusted Per Company 1/ (a)	Under Present Rates: Public Staff Adjustments 2/ (b)	Under Present Rates: After Public Staff Adjustments 3/ (c)	After Public Staff Recommended Increase: Rate Increase (d)	After Public Staff Recommended Increase: After Rate Increase 5/ (e)
1	Electric plant in service	$19,271,521	($167,488)	$19,104,033	$0	$19,104,033
2	Accumulated depreciation and amortization	(8,099,540)	103,858	(7,995,682)	-	(7,995,682)
3	Net electric plant in service (L1 + L2)	$11,171,981	($63,631)	$11,108,350	$0	$11,108,350
4	Materials and supplies	582,130	(3,379)	578,751	-	578,751
	Other Working Capital					
5	Operating funds per lead-lag study	130,416	52,268	182,684	$11,355 4/	194,039
6	Unamortized debt	32,019	-	32,019	-	32,019
7	Regulatory assets and liabilities	447,714	(1,139,114)	(691,400)	-	(691,400)
8	Other	(13,453)	-	(13,453)	-	(13,453)
9	Total other working capital (Sum of L5 through L8)	596,696	(1,086,846)	(490,150)	11,355	(478,795)
10	ARO-related CCR regulatory assets and liabilities	-	142,237	142,237	-	142,237
11	Customer deposits	(116,588)	-	(116,588)	-	(116,588)
12	Accumulated deferred income taxes	(1,534,708)	783,981	(750,727)	-	(750,727)
13	Adjustments to federal excess deferred income taxes	-	23,470	23,470	-	23,470
14	Operating reserves	(54,705)	257	(54,448)	-	(54,448)
15	Construction work in progress	-	-	-	-	-
16	Total original cost rate base (L3 + L4 + L9 + sum of L10 through L15)	$10,644,806	($203,910)	$10,440,896	$11,355	$10,452,251

1/ Based on Smith Supplemental Exhibit 1, Page 4.
2/ Dorgan Supplemental Exhibit 1, Schedule 2-1, Column (q).
3/ Column (a) plus Column (b).
4/ Dorgan Supplemental Exhibit 1, Schedule 2-1(g), Line 80, Column (k).
5/ Column (c) plus Column (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1
Page 1 of 3

Line No.	Item		Update Plant and Accumulated Depreciation to 2/29/2020 2/	Remove EDIT Refund for Treatment as a Rider 3/	Include Flowback of Protected EDIT due to Tax Cuts & Jobs Act 4/	Adjust Depreciation Rates 5/	Adjust Severance Costs 6/	Adjust Storm Deferral 7/	Adjust Coal Inventory 8/
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Electric plant in service		$0	$0	$0	$0	$0	($18,133)	$0
2	Accumulated depreciation and amortization		(1)	-	-	42,779	-	1,812	-
3	Net electric plant in service (L1 + L2)		($1)	$0	$0	$42,779	$0	($16,321)	$0
4	Materials and supplies		-	-	-	-	-	-	(0)
	Other Working Capital								
5	Operating funds per lead-lag study		-	-	-	-	-	-	-
6	Unamortized debt		-	-	-	-	-	-	-
7	Regulatory assets and liabilities		-	-	-	-	(21,655)	(604,202)	-
8	Other		-	-	-	-	-	-	-
9	Total Working Capital		-	-	-	-	(21,655)	(604,202)	-
10	ARO-related CCR regulatory assets and liabilities		-	-	-	-	-	-	-
11	Customer deposits		-	-	-	-	-	-	-
12	Accumulated deferred income taxes		-	538,063	-	-	5,017	139,989	-
13	Adjustments to federal excess deferred income taxes		-	-	23,470	-	-	-	-
14	Operating reserves		-	-	-	-	-	-	-
15	Construction work in progress		-	-	-	-	-	-	-
16	Total original cost rate base (L3 + L4 + L9 + sum of L10 through L15)		($1)	$538 063	$23 470	$42 779	($16 637)	($480 534)	($0)
17	Revenue requirement impact	1/	$0	$42,729	$1,864	$3,397	($1,321)	($38,161)	$0

1/ Line 14 times rate base retention factor of 0 0794134 from Dorgan Exhibit 1, Schedule 1-2.
2/ Dorgan Exhibit 1, Schedule 2-1(a).
3/ Dorgan Exhibit 1, Schedule 2-1(b).
4/ Dorgan Exhibit 1, Schedule 3-1(d).
5/ Dorgan Exhibit 1, Schedule 3-1(e).
6/ Dorgan Exhibit 1, Schedule 3-1(h).
7/ Dorgan Exhibit 1, Schedule 3-1(m).
8/ Dorgan Exhibit 1, Schedule 2-1(d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1

Line No.	Item	Adjustment to Reclassify CCR Reg. Assets & Liabilities 9/	Adjustment to Deferred Non-ARO Environmental Costs 9/	Adjustment to Remove Deferred Environmental Costs - ARO 9/	Adjustment to Remove Rate Case Expense 10/	Adjustment to COSS - SWP&A Reallocation 11/	Adjust Asheville CC Plant in Service Costs 12/	Adjust Asheville CC Deferral
		(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Electric plant in service	$ -	$ -	$ -	$ -	($144,350)	$ -	$ -
2	Accumulated depreciation and amortization	-	-	-	-	59,268	-	-
3	Net electric plant in service (L1 + L2)	$0	$0	$0	$0	($85,081)	$0	$0
4	Materials and supplies	-	-	-	-	(3,379)	0	-
	Other Working Capital							
5	Operating funds per lead-lag study	-	-	-	(2,670)	5,079	-	-
6	Unamortized debt	-	-	-	-	-	-	-
7	Regulatory assets and liabilities	(494,329)	3,958	-	-	-	(22,886)	-
8	Other	-	-	-	-	-	-	-
9	Total Working Capital	(494,329)	3,958	-	(2,670)	5,079	(22,886)	-
10	ARO-related CCR regulatory assets and liabilities	494,329	-	(352,092)	-	-	-	-
11	Customer deposits	-	-	-	-	-	-	-
12	Accumulated deferred income taxes	-	(917)	81,577	$619	14,330	5,303	-
13	Adjustments to federal excess deferred income taxes	-	-	-	-	-	-	-
14	Operating reserves	-	-	-	-	257	-	-
15	Construction work in progress	-	-	-	-	-	-	-
16	Total original cost rate base (L3 + L4 + L9 + sum of L10 through L15)	$0	$3 041	($270 515)	($2 051)	($68 793)	($17 583)	$0
17	Revenue requirement impact 1/	$0	$241	($21,483)	($163)	($5,463)	($1,396)	$0

9/ Based on recommendation of Public Staff witness Maness.
10/ Dorgan Exhibit 1, Schedule 3-1(r).
11/ Dorgan Exhibit 1, Schedule 2-1(e).
12/ Dorgan Exhibit 1, Schedule 3-1(t).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF RATE BASE ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1
Page 3 of 3

Line No.	Item		Adjust W. Asheville Vanderbilt 115kV Project 13/	Adjust Cash Working Capital 14/	Total Rate Base Adjustments 15/
			(o)	(p)	(q)
1	Electric plant in service		($5,006)	$0	($167,488)
2	Accumulated depreciation and amortization		-	-	103,858
3	Net electric plant in service (L1 + L2)		($5,006)	$0	($63,631)
4	Materials and supplies		-	-	(3,379)
	Other Working Capital				
5	Operating funds per lead-lag study		-	49,859	52,268
6	Unamortized debt		-	-	-
7	Regulatory assets and liabilities		-	-	(1,139,114)
8	Other		-	-	-
9	Total Working Capital		-	49,859	(1,086,846)
10	ARO-related CCR regulatory assets and liabilities		-	-	142,237
11	Customer deposits		-	-	-
12	Accumulated deferred income taxes		-	-	783,981
13	Adjustments to federal excess deferred income taxes		-	-	23,470
14	Operating reserves		-	-	257
15	Construction work in progress		-	-	-
16	Total original cost rate base (L3 + L4 + L9 + sum of L10 through L15)		($5 006)	$49 859	($203 910)
17	Revenue requirement impact	1/	($398)	$3,959	($16,193)

13/ Dorgan Exhibit 1, Schedule 2-1(c).
14/ Dorgan Exhibit 1, Schedule 2-1(f), Line 83
15/ Sum of Columns (a) through Column (p).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO UPDATE PLANT AND ACCUMULATED DEPRECIATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplementa
Schedule 2-1(a)

Line No.	Item	Plant in Service (a)		Accumulated Depreciation (b)	
1	Adjustment to update balances to 2/29/2020	$0	1/	$0	2/
2	Adjustment for annualization of depreciation expense	0		(2)	3/
3	Total adjustment to update plant and accumulated depreciation (L1 + L2)	$0		($1)	

1/ Dorgan Supplemental Exhibit 1, Schedule 2-1(a)(1), Line 24, Column (g).
2/ Dorgan Supplemental Exhibit 1, Schedule 2-1(a)(2), Line 14, Column (e).
3/ Dorgan Supplemental Exhibit 1, Schedule 3-1(a), negative of Line 4.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO UPDATE PLANT IN SERVICE TO FEBRUARY 29, 2020
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1(a)(1)

Line No.	Item	Total System Amount As Of 12/31/2018 1/	Total System Amount As Of 2/29/2020 2/	Total System Change in Plant in Service 3/	NC Retail Percentage 4/	NC Retail Amount	
		(a)	(b)	(c)	(f)	(g)	
1	Steam plant	$3,923,116	$3,730,947	($192,169)	60.8591%	($116,952)	5/
2	Direct Assignment - NC steam production	($29,085)	($28,951)	134	100.0000%	134	5/
3	Direct Assignment - SC steam production	$0	$0	-	0.0000%	-	5/
4	Direct Assignment - WSH steam production	($1,188)	($5,802)	(4,614)	0.0000%	-	5/
5	Hydro plant	143,939	157,186	13,247	60.8591%	8,062	5/
6	Other production plant	3,137,412	3,968,488	831,077	60.8591%	505,786	5/
7	Direct Assignment - NC other production	(639)	(639)	-	100.0000%	-	5/
8	Direct Assignment - SC other production	-		-	0.0000%	-	5/
9	Direct Assignment - WSH other production	(1)	(301)	(300)	0.0000%	-	5/
10	Nuclear plant	9,053,408	9,383,475	330,067	60.8591%	200,876	5/
11	Direct Assignment - NC nuclear production	(687,732)	(684,798)	2,934	100.0000%	2,934	5/
12	Direct Assignment - SC nuclear production	(88,565)	(88,213)	352	0.0000%	-	5/
13	Direct Assignment - WSH nuclear production	(153,008)	(152,640)	368	0.0000%	-	5/
14	Total production plant	15,297,657	16,278,752	981,095			
15	Transmission plant	2,745,782	3,009,889	264,107	58.8448%	155,413	5/
16	Distribution plant	6,779,513	7,410,982	631,469	87.1486%	550,316	5/
17	General plant	611,462	688,873	77,411	73.7686%	57,105	5/
18	Intangible plant	494,528	600,193	105,665	67.3953%	71,213	5/
19	Total plant in service	$25,928,941	$27,988,689	$2,059,747		$1,434,886	
20	Update to plant per Public Staff (L19)					$1,434,886	
21	Less: Additional plant recovered in riders					0	
22	Update to plant per Public Staff (L20 - L21)					$1,434,886	
23	Company Adjustment					1,434,886	6/
24	Public Staff adjustment to update plant (L22 - L23)					$0	

1/ NCUC Form E-1, Item 10, NC-1008(E), Column (a) (Line itemized totals per Lines 2 to 9, less corresponding rider recovery assets per Lines 43 to 49).
2/ NCUC Form E-1, Item 10, NC-1008(E), Column (o) (Line itemized totals per Lines 2 to 9, less corresponding rider recovery assets per Lines 43 to 49).
3/ Column (b) minus Column (a).
4/ NCUC Form E-1, Item No. 45B.
5/ Column (e) multiplied by Column (f).
6/ NCUC Form E-1, NC-1001(E), Item No. 10, Total NC Retail column, Line 24, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO UPDATE ACCUMULATED DEPRECIATION TO FEBRUARY 29, 2020
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1(a)(2)

Line No.	Item	Total System: Amount As Of 12/31/2018 1/	Total System: Amount As Of 2/29/2020 2/	Total System: Change in Accumulated Depreciation 3/	NC Retail Percentage 4/	NC Retail Amount	
		(a)	(b)	(c)	(d)	(e)	
1	Production plant	($7,230,278)	($7,308,357)	($78,079)	60.8591%	($47,518)	5/
2	Direct Assignment - NC Production	152,450	180,082	27,632	100.0000%	27,632	5/
3	Direct Assignment - SC Production	17,429	20,143	2,714	0.0000%	-	5/
4	Direct Assignment - WSH Production	108,456	110,081	1,625	0.0000%	-	5/
5	Transmission plant	(817,520)	(850,404)	(32,884)	58.8448%	(19,351)	5/
6	Distribution plant	(3,191,028)	(3,199,578)	(8,550)	87.1486%	(7,451)	5/
7	General plant	(162,646)	(182,168)	(19,522)	73.7686%	(14,401)	5/
8	Intangible plant	(290,400)	(356,387)	(65,987)	67.3953%	(44,472)	5/
9	Total accumulated depreciation	($11,413,537)	($11,586,588)	($173,051)		($105,561)	
10	Change in accumulated depreciation (L9)					($105,561)	
11	Less: Non-fuel rider activity					0	
12	Public Staff adjustment to update through 2/29/2020					($105,561)	
13	Company Adjustment					(105,561)	6/
14	Public Staff adjustment (L10 - L11)					$0	

1/ NCUC Form E-1, Item No. 10, NC-1009(E).

2/ NCUC Form E-1, Item No. 10, NC-1009(E), Column (o) (Line itemized totals per Lines 2 to 9, less accumulated depreciation on corresponding rider recovery assets per Lines 46 to 52).

3/ Column (b) minus Column (a).

4/ NCUC Form E-1, Item No. 45B

5/ Column (c) times Column (d).

6/ NCUC Form E-1, Item No. 10, NC-1001(E), Line 35, Total NC Retail Column, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO ACCUMULATED DEPRECIATION
FOR ANNUALIZATION OF DEPRECIATION EXPENSE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1(a)(3)

Line No.	Item	Annualized Depreciation Expense at 2/29/2020 1/	Per Books Depreciation Expense for Twelve Months Ended 2/29/2020 2/	Difference 3/	NC Retail Percentage 4/	NC Retail Amount
		(a)	(b)	(c)	(d)	(e)
1	Production plant	$570,299	$543,668	$26,631	60.8591%	$16,207 5/
2	Direct Assignment - NC Production	(418)	(437)	19	100.0000%	19
3	Direct Assignment - SC Production			-	0.0000%	-
4	Direct Assignment - WSH Production	(188)	2	(190)	0.0000%	-
5	Transmission plant	55,668	52,649	3,019	58.8448%	1,777 5/
6	Direct Assignment - OATT transmission	(94)	(89)	(5)	0.0000%	-
7	Distribution plant	184,551	176,426	8,125	87.1486%	7,081 5/
8	Direct Assignment - OATT distribution	(3)	(3)	-	0.0000%	-
9	General plant	22,746	28,613	(5,867)	73.7686%	(4,328) 5/
10	Direct Assignment - OATT general	(7)	(7)	-	0.0000%	-
11	Intangible plant	55,511	55,293	218	67.3953%	147 5/
12	Total accumulated depreciation	$888,065	$856,115	$31,950		$20,903
13	Adjustment to accumulated depreciation (-L12)					($20,903)
14	Company Adjustment					(20,901) 6/
15	Public Staff adjustment to accumulated depreciation					($2)

1/ NCUC Form E-1, Item No. 10, NC-1007(E), Current Rates Calculated Column.

2/ NCUC Form E-1, Item No. 10, NC-1007(E), Column (o) (Asset class subtotals per Lines 1 to 52, less annualized depreciation provisions corresponding to rider recovery assets per Lines 55 to 60).

3/ Column (a) minus Column (b).

4/ NCUC Form E-1, Item No. 45B

5/ Column (c) multiplied by Column (d).

6/ NCUC Form E-1, Item No. 10, NC-1001(E), Line 36, NC Retail Column, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO RATE BASE FOR TREATMENT AS A RIDER
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1(b)

Line No.	Item	Amount	
1	Adjustments required to flow back refunds to customers through a Rider:		
2	Adjustment to remove federal unprotected EDIT from rate base	($403,750)	1/
3	Adjustment to remove N.C. state EDIT from rate base	(23,998)	2/
4	Adjustment to remove over collection of revenues due to FIT rate change from rate base	(110,315)	3/
5	Public Staff Adjustments to rate base for tax changes (Sum of Lines 2 through 4)	($538,063)	

1/ Smith Supplemental Exhibit 4, Line 8, Columns (b) and (c).
2/ Smith Supplemental Exhibit 4, Line 8, Columns (d).
3/ Smith Supplemental Exhibit 4, Line 8, Column (e).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO VANDERBILT - W. ASHEVILLE VANDERBILT 115KV PROJECT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1(c)

Line No.	Item	Amount	
1	W. Asheville - Vanderbilt 115kV Project Allocated at 100% to NC Retail per Company at 12/2018	$11,727	1/
2	W. Asheville - Vanderbilt 115kV Project Allocated at Transmission Level per Public Staff at 12/2018	6,901	2/
3	Total Public Staff adjustment to W. Asheville - Vanderbilt 115kV Project at 12/2018 (L2 - L1)	($4,826)	
4	W. Asheville - Vanderbilt 115kV Project distribution post test year additions at 12/2019	$634	1/
5	NC Retail Distribution allocation per Public Staff	87.1486%	
6	W. Asheville - Vanderbilt 115kV Project distribution post test year additions per Company	553	
7	NC Retail Transmission allocation per Public Staff	58.8448%	
8	W. Asheville - Vanderbilt 115kV Project transmission post test year additions per Public Staff	373	
9	Total Public Staff adjustment to W. Asheville - Vanderbilt 115kV Project PTA (L8 - L6) at 12/2019	(180)	
10	Total Public Staff adjustment to W. Asheville - Vanderbilt 115kV Project (L3 + L9)	(5,006)	

1/ Based on information provided by Company.
2/ Line 1 times SWPA NC Retail Allocation factor for Transmission Plant (DT) of 58.8448%.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO COAL INVENTORY
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1(d)

Line No.	Item	Total System		NC Retail Allocation		Total NC Retail	
1	Estimated full load burn - excluding retirements, in tons	32,017	1/				
2	Target number of days inventory	35	1/				
3	Target coal inventory balance at December 31, 2018 (L1 x L2)	1,120,595					
4	Projected average delivered coal cost per ton	$ 65.43	2/				
5	Projected coal inventory balance at target (L3 x L4/1,000)	$ 73,321		61.1093%	3/	$44,806	
6	Adjust for Fixed Transportation Costs	13,977	4/	61.1093%	3/	8,541	
7	Total coal inventory balance at target	$ 87,298				$ 53,347	
8	Actual coal inventory balance per Company	106,285	5/	61.1093%	3/	64,950	
9	Impact to materials and supplies (L7 - L8)	(18,987)				(11,603)	
10	Company Adjustment					(11,603)	6/
11	Adjustment to coal inventory (L9 - L10)					($0)	

1/ NCUC Form E-1, Item 46E, Coal Consumption and Inventory Data.
2/ Based on recommendation of Public Staff witness Metz.
3/ NCUC Form E-1, Item No. 45B, SWP&A Allocation Factor: E1.
4/ Per Public Staff witness Metz, the average delivered cost/ton does not include fixed transportation costs. The delivered cost of fuel used here is consistent with Docket No E-2, Sub 1204 with a projected period of 12/1/2019 - 11/30/2020.
=Target inventory balance in tons/estimated coal delivered in tons * Transportation Cost
5/ NCUC Form E-1, Item 10, NC-2401, Line 10.
6/ NCUC Form E-1, Item No. 10, NC-2401(C), Line 12, N.C. Retail Column, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ORIGINAL COST RATE BASE, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1(e)

		North Carolina Retail Operations		
Line No.	Item	SWP&A Company Rate Base Reallocated By Public Staff 1/	Summer CP Company Rate Base - Company Allocations 2/	Public Staff Adjustment: SWP&A Reallocation 3/
		(a)	(b)	(c)
1	Electric plant in service	$19,127,171	$19,271,521	($144,350)
2	Accumulated depreciation and amortization	(8,040,272)	(8,099,540)	59,268
3	Net electric plant in service (L1 + L2)	$11,086,900	$11,171,981	($85,081)
4	Materials and supplies	578,751	582,130	(3,379)
5	Working capital investment	485,187	480,108	5,079
6	Accumulated deferred taxes	(1,520,378)	(1,534,708)	14,330
7	Operating reserves	(54,448)	(54,705)	257
8	Construction work in progress	-	-	-
9	Total Original Cost Rate Base (Sum of L3 through L8)	$10,576,013	$10,644,806	($68,793)

1/ Dorgan Supplemental Exhibit III, Schedule 1, Column (c).
2/ Dorgan Supplemental Exhibit I, Schedule 2, Column (a).
3/ Column (a) - Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY UNDER PRESENT RATES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1(f)

Line No.	Item	Per Books Amounts 1/	Company Ratemaking Adjustments 2/	After Company Adjustments 3/	Public Staff Adjustments 4/	After Public Staff Adjustments 5/	Lead / Lag Days 6/	Working Capital From Lead/ Lag Study 7/
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Electric operating revenues:							
2	Rate revenues	$3,575,788	$ (296,494)	$3,279,294	$3,145	$3,282,438	41.88	$376,626
3	Sales for resale revenues	134,915	-	134,915	-	134,915	33.73	12,468
4	Provisions for rate refunds	(104,546)	-	(104,546)	-	(104,546)	41.88	(11,996)
5	Forfeited discounts	7,664	-	7,664	-	7,664	72.30	1,518
6	Miscellaneous service revenues	5,506	-	5,506	-	5,506	76.00	1,146
7	Rent revenues - production plant related	4,466	-	4,466	-	4,466	41.63	509
8	Rent revenues - distribution pole rental revenue	10,901	-	10,901	-	10,901	182.00	5,436
9	Rent revenues - transmission plant related	382	-	382	-	382	41.63	44
10	Rent revenues - additional facilities - wholesale	-	-	-	-	-	-	-
11	Rent revenues - additional facilities - ret X lighting	4,617	-	4,617	-	4,617	41.63	527
12	Rent revenues - additional facilities - lighting	3,849	-	3,849	-	3,849	41.63	439
13	Rent revenues - other	3,413	-	3,413	-	3,413	68.21	638
14	Other revenues - production plant related	1,184	-	1,184	-	1,184	41.88	136
15	Other revenues - transmission related	6,208	-	6,208	-	6,208	41.88	712
16	Other revenues - wholesale D/A	368	-	368	-	368	41.88	42
17	Other revenues - REPS	1,114	-	1,114	-	1,114	41.88	128
18	Other revenues - other energy	-	-	-	-	-	-	-
19	Other revenues - distribution plant related	1,404	-	1,404	-	1,404	41.88	161
20	Other revenues - NC retail specific	271	-	271	-	271	41.88	31
21	Electric operating revenues	3,657,503	(296,494)	3,361,009	3,145	3,364,154	42.16	388,565
22	Fuel used in electric generation:							
23	O&M production energy - fuel	863,120	(29,976)	833,144	442	833,586	28.49	65,065
24	RECS consumption expense	18,522	-	18,522	-	18,522	28.49	1,446
25	Fuel used in electric generation	881,642	(29,976)	851,666	442	852,108	28.49	66,511
26	Purchased power:							
27	O&M production purchases - capacity cost	67,280	-	67,280	-	67,280	30.29	5,583
28	O&M production purchases - energy cost	365,384	(1,965)	363,419	(710)	362,709	30.29	30,100
29	O&M deferred fuel expense	(273,901)	-	(273,901)	-	(273,901)	28.49	(21,379)
30	Purchased power	158,763	(1,965)	156,798	(710)	156,088	33.45	14,304
31	Other O&M expense:							
32	Labor expense	430,295	(22,193)	408,102	(16,290)	391,812	37.07	39,793
33	Pension & benefits	76,271	(6,358)	69,913	-	69,913	13.97	2,676
34	Regulatory commission expense	7,038	(234)	6,804	-	6,804	93.25	1,738
35	Property insurance	(526)	-	(526)	-	(526)	(222.30)	320
36	Injuries & damages - workman's compensation	197	-	197	-	197	-	-
37	Uncollectible accounts	8,937	-	8,937	-	8,937	-	-
38	Other O&M expense	528,607	4,875	533,482	(29,598)	503,884	40.52	55,938
39	Adjust for other revenue		(1,025)	(1,025)	-	(1,025)	37.32	(105)
40	Adjust for non fuel riders/aviation/merger		(141,634)	(141,634)	-	(141,634)	37.32	(14,482)
41	Adjust for non-labor O&M		1,319	1,319	-	1,319	33.30	120
42	Adjust for rate case expense/reg assets & liabilities		2,304	2,304	-	2,304	-	-
43	Adjust for Severance		(24,140)	(24,140)	-	(24,140)	37.07	(2,452)
44	Adjust for Outside Services		-	-	(146)	(146)	37.07	(15)
45	Adjust for Asheville Plants (Steam & CC) and CertainTeed		(304)	(304)	-	(304)	37.32	(31)
46	Other adjustments to regulatory fees and uncollectibles		-	-	-	-	-	-
47	Total Other O&M expenses	1,050,819	(187,389)	863,429	(46,034)	817,395	37.29	83,500
48	Depreciation | amortization | P&C losses:							
49	Depreciation & amortization	669,787	280,272	950,059	(179,767)	770,292	-	-
50	Adjust other amortization expense		-	-	(30,548)	(30,548)	-	-
51	Total depreciation & amortization expense	669,787	280,272	950,059	(210,315)	739,745	-	-
52	Taxes other than income taxes:							
53	Payroll taxes	26,288	(1,227)	25,061	-	25,061	48.41	3,324
54	Property taxes	68,133	9,027	77,160	-	77,160	186.50	39,425
55	Other taxes - federal heavy vehicle use tax	48	-	48	63	111	-	-
56	Other taxes - electric excise tax - SC	-	-	-	-	-	-	-
57	Other taxes - privilege tax	12,244	-	12,244	-	12,244	(11.97)	(402)
58	Miscellaneous taxes - NC	(4,517)	-	(4,517)	(690)	(5,207)	60.00	(856)
59	Miscellaneous taxes - SC & other states	1	-	1	-	1	129.46	-
60	Other taxes - PUC license tax - SC	-	-	-	-	-	-	-
61	Adjust costs recovered through non-fuel riders		(6,458)	(6,458)	-	(6,458)	137.26	(2,429)
62	Adjust to reflect retirement of Asheville Steam Generating Plant		(1,032)	(1,032)	-	(1,032)	186.50	(527)
63	Total taxes other than income taxes	102,197	310	102,507	(627)	101,880	138.06	38,535
64	Interest on customer deposits	7,971	-	7,971	-	7,971	137.50	3,003
65	Income taxes:							
66	Federal income taxes	(49,091)	49,091	-	-	-	44.75	-
67	State income taxes	(2,917)	2,917	-	-	-	44.75	-
68	Income taxes - deferred	164,994	(164,994)	(0)	-	(0)	-	-
69	Adjust NC income taxes for rate change | Synchronize interest			-				-
70	expense		(128,708)	(128,708)	-	(128,708)	20.60	(7,264)
71	Adjust costs recovered through non-fuel riders		63,168	63,168	-	63,168	-	-
72	Adjust for Federal & State income taxes		112,986	112,986	58,897	171,883	20.60	9,701
73	Total income taxes	112,986	(65,540)	47,446	58,897	106,343	8.36	2,437
74	Amortization of ITC	(2,134)	(1,481)	(3,615)	34	(3,581)	-	-
75	Total utility operating expenses	2,982,032	(5,770)	2,976,262	(198,313)	2,777,949	27.37	208,290
76	Interest expense	211,661	(3,394)	208,267	5,733	214,000	-	-
77	Income available for common equity	463,810	(287,330)	176,480	-	176,480	-	-
78	Net operating income for return	675,472	(290,724)	384,748	5,733	390,480	-	-
79	Total requirement	3,657,503	(296,494)	3,361,009	(192,581)	3,168,429	23.99	208,290
80	Cash working capital per Public Staff, before Sales Tax Adjustment (L21 - (L75 + L76))							180,275
81	Amount per Books per Company application						160,141 8/	
82	ADD(LESS): Accounting Adjustments						(29,725) 8/	130,416 8/
83	Adjustment to cash working capital							49,859

1/ NCUC Form E-1, Item No. 14, Lead Lag Summary Detail, NC Retail Jurisdictional Amount.
2/ Smith Supplemental Exhibit 1.
3/ Column (a) plus Column (b).
4/ Dorgan Supplemental Exhibit 1, Schedule 2-1(f)(1), Column (ad).
5/ Column (c) plus Column (d).
6/ NCUC Form E-1, Item No. 14, Lead Lag Summary Detail, as corrected by the Company.
7/ Column (e) divided by 365 days, multiplied by Column (f).
8/ Smith Supplemental Exhibit 1, Page 4d, Line 1, Columns (2), (3), and (4)

DUKE ENERGY PROGRESS, LLC
Docket No. E 2, Sub 1219
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN
LEAD LAG CALCULATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2 1(f)(1)
Page 1 of 5

Line No.	Item	Update Plant to 2/29/2020 1/	Update Revenues/ Customer Growth/ Weather to 2/29/2020 1/	Adjust Credit Card Fees 1/	Remove EDIT Refunds for Treatment as Riders 1/	Include Flowback EDIT due to Tax Cuts & Jobs Act 1/	Adjust Depreciation Rates 1/
		(a)	(b)	(c)	(d)	(e)	(f)
1	Electric operating revenues						
2	Rate revenues	$0	$3,311	$0	$0	$0	$0
3	Sales for resale revenues	-	-	-	-	-	-
4	Provisions for rate refunds	-	-	-	-	-	-
5	Forfeited discounts	-	-	-	-	-	-
6	Miscellaneous service revenues	-	-	-	-	-	-
7	Rent revenues - production plant related	-	-	-	-	-	-
8	Rent revenues - distribution pole rental revenue	-	-	-	-	-	-
9	Rent revenues - transmission plant related	-	-	-	-	-	-
10	Rent revenues - additional faci ities - wholesale	-	-	-	-	-	-
11	Rent revenues - additional faci ities - ret X lighting	-	-	-	-	-	-
12	Rent revenues - additional faci ities - ighting	-	-	-	-	-	-
13	Rent revenues - other	-	-	-	-	-	-
14	Other revenues - production plant related	-	-	-	-	-	-
15	Other revenues - transmission related	-	-	-	-	-	-
16	Other revenues - wholesale D/A	-	-	-	-	-	-
17	Other revenues - REPS	-	-	-	-	-	-
18	Other revenues - other energy	-	-	-	-	-	-
19	Other revenues - distribution plant related	-	-	-	-	-	-
20	Other revenues - NC retail specific	-	-	-	-	-	-
21	Electric operating revenues	-	3 311	-	-	-	-
22	Fuel used in electric generation						
23	O&M production energy - fuel	-	442	-	-	-	-
24	RECS consumption expense	-	-	-	-	-	-
25	Fuel used in electric generation	-	442	-	-	-	-
26	Purchased power						
27	O&M production purchases - capacity cost	-	-	-	-	-	-
28	O&M production purchases - energy cost	-	-	-	-	-	-
29	O&M deferred fuel expense	-	-	-	-	-	-
30	Purchased power	-	-	-	-	-	-
31	Other O&M expense						
32	Labor expense	-	-	-	-	-	-
33	Pension & benefits	-	-	-	-	-	-
34	Regulatory commission expense	-	-	-	-	-	-
35	Property insurance	-	-	-	-	-	-
36	Injuries & damages - workman's compensation	-	-	-	-	-	-
37	Uncollectible accounts	-	-	-	-	-	-
38	Other O&M expense	-	(4,532)	(95)	-	-	-
39	Adjust for other revenue	-	-	-	-	-	-
40	Adjust for non fuel riders/aviation/merger	-	-	-	-	-	-
41	Adjust for non-labor O&M	-	-	-	-	-	-
42	Adjust for rate case expense/reg assets & liabilities	-	-	-	-	-	-
43	Adjust for Severance	-	-	-	-	-	-
44	Adjust for Outside Services	-	-	-	-	-	-
45	Adjust for Asheville Plants (Steam & CC) and CertainTeed	-	-	-	-	-	-
46	Other adjustments to regulatory fees and uncollectibles	-	-	-	-	-	-
47	Total Other O&M expenses	-	(4,532)	(95)	-	-	-
48	Depreciation | amortization | P&C losses						
49	Depreciation & amortization	(224)	-	-	-	-	(42,779)
50	Adjust other amortization expense	-	-	-	-	(30,548)	-
51	Total depreciation & amortization expense	(224)	-	-	-	(30 548)	(42 779)
52	Taxes other than income taxes						
53	Payroll taxes	-	-	-	-	-	-
54	Property taxes	-	-	-	-	-	-
55	Other taxes - federal heavy vehicle use tax	65	-	-	-	-	-
56	Other taxes - electric excise tax - SC	-	-	-	-	-	-
57	Other taxes - privilege tax	-	-	-	-	-	-
58	Miscellaneous taxes - NC	-	-	-	-	-	-
59	Miscellaneous taxes - SC & other states	-	-	-	-	-	-
60	Other taxes - PUC license tax - SC	-	-	-	-	-	-
61	Adjust costs recovered through non-fuel riders	-	-	-	-	-	-
62	Adjust to reflect retirement of Asheville Steam Generating Plant	-	-	-	-	-	-
63	Total taxes other than income taxes	65	-	-	-	-	-
64	Interest on customer deposits	-	-	-	-	-	-
65	Income taxes						
66	Federal income taxes	-	-	-	-	-	-
67	State income taxes	-	-	-	-	-	-
68	Income taxes - deferred	-	-	-	-	-	-
69	Adjust NC income taxes for rate change | Synchronize interest						
70	expense	-	-	-	-	-	-
71	Adjust costs recovered through non-fuel riders	-	-	-	-	-	-
72	Adjust for Federal & State income taxes	37	1,715	22	-	7,078	9,912
73	Total income taxes	37	1 715	22	-	7 078	9 912
74	Amortization of ITC	-	-	-	-	-	-
75	Total utility operating expenses	(122)	(2 375)	(73)	-	(23 470)	(32 867)
76	Interest expense	-	-	-	-	-	-
77	Income available for common equity 2/	122	5,686	73	-	23,470	32,867
78	Net operating income for return	122	5 686	73	-	23 470	32 867
79	Total requirement	-	3,311	-	-	-	-

1/ Based on adjustments made by Public Staff in Dorgan Supplemental Exhibit 1, Schedule 3-1.
2/ Line 21 minus Line 75 minus Line 77.
3/ Sum of Columns (a) through Column (ad).

DUKE ENERGY PROGRESS, LLC
Docket No. E 2, Sub 1219
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN
LEAD LAG CALCULATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2 1(f)(1)
Page 2 of 5

Line No.	Item	Adjust Salaries & Wages 1/	Adjust Incentives 1/	Adjust Severance Costs 1/	Adjust Executive Compensation 1/	Adjust Aviation Expenses 1/	Adjust EOL Nuclear M&S Reserve Amortization 1/
		(g)	(h)	(i)	(j)	(k)	(l)
1	Electric operating revenues						
2	Rate revenues	$0	$0	$0	$0	$0	$0
3	Sales for resale revenues	-	-	-	-	-	-
4	Provisions for rate refunds	-	-	-	-	-	-
5	Forfeited discounts	-	-	-	-	-	-
6	Miscellaneous service revenues	-	-	-	-	-	-
7	Rent revenues - production plant related	-	-	-	-	-	-
8	Rent revenues - distribution pole rental revenue	-	-	-	-	-	-
9	Rent revenues - transmission plant related	-	-	-	-	-	-
10	Rent revenues - additional faci ities - wholesale	-	-	-	-	-	-
11	Rent revenues - additional faci ities - ret X lighting	-	-	-	-	-	-
12	Rent revenues - additional faci ities - ighting	-	-	-	-	-	-
13	Rent revenues - other	-	-	-	-	-	-
14	Other revenues - production plant related	-	-	-	-	-	-
15	Other revenues - transmission related	-	-	-	-	-	-
16	Other revenues - wholesale D/A	-	-	-	-	-	-
17	Other revenues - REPS	-	-	-	-	-	-
18	Other revenues - other energy	-	-	-	-	-	-
19	Other revenues - distribution plant related	-	-	-	-	-	-
20	Other revenues - NC retail specific	-	-	-	-	-	-
21	Electric operating revenues	-	-	-	-	-	-
22	Fuel used in electric generation						
23	O&M production energy - fuel	-	-	-	-	-	-
24	RECS consumption expense	-	-	-	-	-	-
25	Fuel used in electric generation	-	-	-	-	-	-
26	Purchased power						
27	O&M production purchases - capacity cost	-	-	-	-	-	-
28	O&M production purchases - energy cost	-	-	-	-	-	-
29	O&M deferred fuel expense	-	-	-	-	-	-
30	Purchased power	-	-	-	-	-	-
31	Other O&M expense						
32	Labor expense	-	(14,652)	-	(160)	-	-
33	Pension & benefits	-	-	-	-	-	-
34	Regulatory commission expense	-	-	-	-	-	-
35	Property insurance	-	-	-	-	-	-
36	Injuries & damages - workman's compensation	-	-	-	-	-	-
37	Uncollectible accounts	-	-	-	-	-	-
38	Other O&M expense	-	-	(4,331)	-	(405)	-
39	Adjust for other revenue	-	-	-	-	-	-
40	Adjust for non fuel riders/aviation/merger	-	-	-	-	-	-
41	Adjust for non-labor O&M	-	-	-	-	-	-
42	Adjust for rate case expense/reg assets & liabilities	-	-	-	-	-	-
43	Adjust for Severance	-	-	-	-	-	-
44	Adjust for Outside Services	-	-	-	-	-	-
45	Adjust for Asheville Plants (Steam & CC) and CertainTeed	-	-	-	-	-	-
46	Other adjustments to regulatory fees and uncollectibles	-	-	-	-	-	-
47	Total Other O&M expenses	-	(14,652)	(4,331)	(160)	(405)	-
48	Depreciation | amortization | P&C losses						
49	Depreciation & amortization	-	-	-	-	-	(1,807)
50	Adjust other amortization expense	-	-	-	-	-	-
51	Total depreciation & amortization expense	-	-	-	-	-	(1 807)
52	Taxes other than income taxes						
53	Payroll taxes	-	-	-	-	-	-
54	Property taxes	-	-	-	-	-	-
55	Other taxes - federal heavy vehicle use tax	-	-	-	-	(2)	-
56	Other taxes - electric excise tax - SC	-	-	-	-	-	-
57	Other taxes - privilege tax	-	-	-	-	-	-
58	Miscellaneous taxes - NC	-	-	-	-	-	-
59	Miscellaneous taxes - SC & other states	-	-	-	-	-	-
60	Other taxes - PUC license tax - SC	-	-	-	-	-	-
61	Adjust costs recovered through non-fuel riders	-	-	-	-	-	-
62	Adjust to reflect retirement of Asheville Steam Generating Plant	-	-	-	-	-	-
63	Total taxes other than income taxes	-	-	-	-	(2)	-
64	Interest on customer deposits	-	-	-	-	-	-
65	Income taxes						
66	Federal income taxes	-	-	-	-	-	-
67	State income taxes	-	-	-	-	-	-
68	Income taxes - deferred	-	-	-	-	-	-
69	Adjust NC income taxes for rate change | Synchronize interest						
70	expense	-	-	-	-	-	-
71	Adjust costs recovered through non-fuel riders	-	-	-	-	-	-
72	Adjust for Federal & State income taxes	-	3,395	1,003	37	94	419
73	Total income taxes	-	3 395	1 003	37	94	419
74	Amortization of ITC	-	-	-	-	-	-
75	Total utility operating expenses	-	(11 257)	(3 328)	(123)	(313)	(1 388)
76	Interest expense	-	-	-	-	-	-
77	Income available for common equity 2/	-	11,257	3,328	123	313	1,388
78	Net operating income for return	-	11 257	3 328	123	313	1 388
79	Total requirement	-	-	-	-	-	-

DUKE ENERGY PROGRESS, LLC
Docket No. E 2, Sub 1219
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN
LEAD LAG CALCULATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2 1(f)(1)

Line No.	Item	Adjustment to Remove Deferred Environmental Costs - ARO 1/	Adjustment to Remove Deferred Non-ARO Environmental Costs 1/	Adjust to Normalize Storm Costs 1/	Adjust Storm Deferral 1/	Adjust Lobbying Expense 1/	Adjust Board of Directors Expense 1/
		(m)	(n)	(o)	(p)	(q)	(r)
1	Electric operating revenues						
2	Rate revenues	$0	$0	$0	$0	$0	$0
3	Sales for resale revenues	-	-	-	-	-	-
4	Provisions for rate refunds	-	-	-	-	-	-
5	Forfeited discounts	-	-	-	-	-	-
6	Miscellaneous service revenues	-	-	-	-	-	-
7	Rent revenues - production plant related	-	-	-	-	-	-
8	Rent revenues - distribution pole rental revenue	-	-	-	-	-	-
9	Rent revenues - transmission plant related	-	-	-	-	-	-
10	Rent revenues - additional faci ities - wholesale	-	-	-	-	-	-
11	Rent revenues - additional faci ities - ret X lighting	-	-	-	-	-	-
12	Rent revenues - additional faci ities - ighting	-	-	-	-	-	-
13	Rent revenues - other	-	-	-	-	-	-
14	Other revenues - production plant related	-	-	-	-	-	-
15	Other revenues - transmission related	-	-	-	-	-	-
16	Other revenues - wholesale D/A	-	-	-	-	-	-
17	Other revenues - REPS	-	-	-	-	-	-
18	Other revenues - other energy	-	-	-	-	-	-
19	Other revenues - distribution plant related	-	-	-	-	-	-
20	Other revenues - NC retail specific	-	-	-	-	-	-
21	Electric operating revenues	-	-	-	-	-	-
22	Fuel used in electric generation						
23	O&M production energy - fuel	-	-	-	-	-	-
24	RECS consumption expense	-	-	-	-	-	-
25	Fuel used in electric generation	-	-	-	-	-	-
26	Purchased power						
27	O&M production purchases - capacity cost	-	-	-	-	-	-
28	O&M production purchases - energy cost	-	-	-	-	-	-
29	O&M deferred fuel expense	-	-	-	-	-	-
30	Purchased power	-	-	-	-	-	-
31	Other O&M expense						
32	Labor expense	-	-	-	-	($1,478)	-
33	Pension & benefits	-	-	-	-	-	-
34	Regulatory commission expense	-	-	-	-	-	-
35	Property insurance	-	-	-	-	-	-
36	Injuries & damages - workman's compensation	-	-	-	-	-	-
37	Uncollectible accounts	-	-	-	-	-	-
38	Other O&M expense	-	-	9,300	-	(60)	($1,270)
39	Adjust for other revenue	-	-	-	-	-	-
40	Adjust for non fuel riders/aviation/merger	-	-	-	-	-	-
41	Adjust for non-labor O&M	-	-	-	-	-	-
42	Adjust for rate case expense/reg assets & liabilities	-	-	-	-	-	-
43	Adjust for Severance	-	-	-	-	-	-
44	Adjust for Outside Services	-	-	-	-	-	-
45	Adjust for Asheville Plants (Steam & CC) and CertainTeed	-	-	-	-	-	-
46	Other adjustments to regulatory fees and uncollectibles	-	-	-	-	-	-
47	Total Other O&M expenses	-	-	9,300	-	(1,538)	(1,270)
48	Depreciation | amortization | P&C losses						
49	Depreciation & amortization	(77,167)	(3,958)	-	(44,793)	-	-
50	Adjust other amortization expense	-	-	-	-	-	-
51	Total depreciation & amortization expense	(77 167)	(3 958)	-	(44 793)	-	-
52	Taxes other than income taxes						
53	Payroll taxes	-	-	-	-	-	-
54	Property taxes	-	-	-	-	-	-
55	Other taxes - federal heavy vehicle use tax	-	-	-	-	-	-
56	Other taxes - electric excise tax - SC	-	-	-	-	-	-
57	Other taxes - privilege tax	-	-	-	-	-	-
58	Miscellaneous taxes - NC	-	-	-	-	-	-
59	Miscellaneous taxes - SC & other states	-	-	-	-	-	-
60	Other taxes - PUC license tax - SC	-	-	-	-	-	-
61	Adjust costs recovered through non-fuel riders	-	-	-	-	-	-
62	Adjust to reflect retirement of Asheville Steam Generating Plant	-	-	-	-	-	-
63	Total taxes other than income taxes	-	-	-	-	-	-
64	Interest on customer deposits	-	-	-	-	-	-
65	Income taxes						
66	Federal income taxes	-	-	-	-	-	-
67	State income taxes	-	-	-	-	-	-
68	Income taxes - deferred	-	-	-	-	-	-
69	Adjust NC income taxes for rate change | Synchronize interest						
70	expense	-	-	-	-	-	-
71	Adjust costs recovered through non-fuel riders	-	-	-	-	-	-
72	Adjust for Federal & State income taxes	17,879	917	(2,155)	10,378	356	294
73	Total income taxes	17 879	917	(2 155)	10 378	356	294
74	Amortization of ITC	-	-	-	-	-	-
75	Total utility operating expenses	(59 288)	(3 041)	7 145	(34 415)	(1 182)	(976)
76	Interest expense	-	-	-	-	-	-
77	Income available for common equity 2/	59,288	3,041	(7,145)	34,415	1,182	976
78	Net operating income for return	59 288	3 041	(7 145)	34 415	1 182	976
79	Total requirement	-	-	-	-	-	-

I/A

DUKE ENERGY PROGRESS, LLC
Docket No. E 2, Sub 1219
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN
LEAD LAG CALCULATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2 1(f)(1)
Page 4 of 5

Line No.	Item	Adjust Outside Services 1/	Adjust Charitable Contributions, and Corporate Sponsorships & Donations 1/	Adjustment to Inflation Adjustment 1/	Adjustment to Remove CertainTeed Payment Obligation 1/	Adjustment to Nuclear Decommissioning Expense 1/	Adjustment to Remove Rate Case Expense 1/
		(s)	(t)	(u)	(v)	(w)	(x)
1	Electric operating revenues						
2	Rate revenues	$0	$0	$0	$0	$0	$0
3	Sales for resale revenues	-	-	-	-	-	-
4	Provisions for rate refunds	-	-	-	-	-	-
5	Forfeited discounts	-	-	-	-	-	-
6	Miscellaneous service revenues	-	-	-	-	-	-
7	Rent revenues - production plant related	-	-	-	-	-	-
8	Rent revenues - distribution pole rental revenue	-	-	-	-	-	-
9	Rent revenues - transmission plant related	-	-	-	-	-	-
10	Rent revenues - additional faci ities - wholesale	-	-	-	-	-	-
11	Rent revenues - additional faci ities - ret X lighting	-	-	-	-	-	-
12	Rent revenues - additional faci ities - ighting	-	-	-	-	-	-
13	Rent revenues - other	-	-	-	-	-	-
14	Other revenues - production plant related	-	-	-	-	-	-
15	Other revenues - transmission related	-	-	-	-	-	-
16	Other revenues - wholesale D/A	-	-	-	-	-	-
17	Other revenues - REPS	-	-	-	-	-	-
18	Other revenues - other energy	-	-	-	-	-	-
19	Other revenues - distribution plant related	-	-	-	-	-	-
20	Other revenues - NC retail specific	-	-	-	-	-	-
21	Electric operating revenues	-	-	-	-	-	-
22	Fuel used in electric generation						
23	O&M production energy - fuel	-	-	-	-	-	-
24	RECS consumption expense	-	-	-	-	-	-
25	Fuel used in electric generation	-	-	-	-	-	-
26	Purchased power						
27	O&M production purchases - capacity cost	-	-	-	-	-	-
28	O&M production purchases - energy cost	-	-	-	-	-	-
29	O&M deferred fuel expense	-	-	-	-	-	-
30	Purchased power	-	-	-	-	-	-
31	Other O&M expense						
32	Labor expense	-	-	-	-	-	-
33	Pension & benefits	-	-	-	-	-	-
34	Regulatory commission expense	-	-	-	-	-	-
35	Property insurance	-	-	-	-	-	-
36	Injuries & damages - workman's compensation	-	-	-	-	-	-
37	Uncollectible accounts	-	-	-	-	-	-
38	Other O&M expense	-	($36)	2,799	(4,939)	(16,537)	(193)
39	Adjust for other revenue	-	-	-	-	-	-
40	Adjust for non fuel riders/aviation/merger	-	-	-	-	-	-
41	Adjust for non-labor O&M	-	-	-	-	-	-
42	Adjust for rate case expense/reg assets & liabilities	-	-	-	-	-	-
43	Adjust for Severance	-	-	-	-	-	-
44	Adjust for Outside Services	(146)	-	-	-	-	-
45	Adjust for Asheville Plants (Steam & CC) and CertainTeed	-	-	-	-	-	-
46	Other adjustments to regulatory fees and uncollectibles	-	-	-	-	-	-
47	Total Other O&M expenses	(146)	(36)	2,799	(4,939)	(16,537)	(193)
48	Depreciation | amortization | P&C losses						
49	Depreciation & amortization	-	-	-	-	-	-
50	Adjust other amortization expense	-	-	-	-	-	-
51	Total depreciation & amortization expense	-	-	-	-	-	-
52	Taxes other than income taxes						
53	Payroll taxes	-	-	-	-	-	-
54	Property taxes	-	-	-	-	-	-
55	Other taxes - federal heavy vehicle use tax	-	-	-	-	-	-
56	Other taxes - electric excise tax - SC	-	-	-	-	-	-
57	Other taxes - privilege tax	-	-	-	-	-	-
58	Miscellaneous taxes - NC	-	-	-	-	-	-
59	Miscellaneous taxes - SC & other states	-	-	-	-	-	-
60	Other taxes - PUC license tax - SC	-	-	-	-	-	-
61	Adjust costs recovered through non-fuel riders	-	-	-	-	-	-
62	Adjust to reflect retirement of Asheville Steam Generating Plant	-	-	-	-	-	-
63	Total taxes other than income taxes	-	-	-	-	-	-
64	Interest on customer deposits	-	-	-	-	-	-
65	Income taxes						
66	Federal income taxes	-	-	-	-	-	-
67	State income taxes	-	-	-	-	-	-
68	Income taxes - deferred	-	-	-	-	-	-
69	Adjust NC income taxes for rate change | Synchronize interest						
70	expense	-	-	-	-	-	-
71	Adjust costs recovered through non-fuel riders	-	-	-	-	-	-
72	Adjust for Federal & State income taxes	34	8	(648)	1,144	3,831	45
73	Total income taxes	34	8	(648)	1 144	3 831	45
74	Amortization of ITC	-	-	-	-	-	-
75	Total utility operating expenses	(112)	(28)	2 151	(3 795)	(12 706)	(148)
76	Interest expense	-	-	-	-	-	-
77	Income available for common equity 2/	112	28	(2,151)	3,795	12,706	148
78	Net operating income for return	112	28	(2 151)	3 795	12 706	148
79	Total requirement	-	-	-	-	-	-

DUKE ENERGY PROGRESS, LLC
Docket No. E 2, Sub 1219
North Carolina Retail Operations
PUBLIC STAFF ADJUSTMENTS TO BE REFLECTED IN
LEAD LAG CALCULATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2 1(f)(1)
Page 5 of 5

Line No.	Item	Adjustment to COSS - SWP&A Reallocation 1/	Adjust Asheville CC Plant in Service Costs 1/	Adjust Asheville CC Deferral 1/	Adjust for Ashev lle Production Displacement 1/	Interest Synchronization 1/	Total Public Staff Adjustments 3/
		(y)	(z)	(aa)	(ab)	(ac)	(ad)
1	Electric operating revenues						
2	Rate revenues	($166)	$0	$0	$0	$0	$3,145
3	Sales for resale revenues	-	-	-	-	-	-
4	Provisions for rate refunds	-	-	-	-	-	-
5	Forfeited discounts	-	-	-	-	-	-
6	Miscellaneous service revenues	-	-	-	-	-	-
7	Rent revenues - production plant related	-	-	-	-	-	-
8	Rent revenues - distribution pole rental revenue	-	-	-	-	-	-
9	Rent revenues - transmission plant related	-	-	-	-	-	-
10	Rent revenues - additional faci ities - wholesale	-	-	-	-	-	-
11	Rent revenues - additional faci ities - ret X lighting	-	-	-	-	-	-
12	Rent revenues - additional faci ities - ighting	-	-	-	-	-	-
13	Rent revenues - other	-	-	-	-	-	-
14	Other revenues - production plant related	-	-	-	-	-	-
15	Other revenues - transmission related	-	-	-	-	-	-
16	Other revenues - wholesale D/A	-	-	-	-	-	-
17	Other revenues - REPS	-	-	-	-	-	-
18	Other revenues - other energy	-	-	-	-	-	-
19	Other revenues - distribution plant related	-	-	-	-	-	-
20	Other revenues - NC retail specific	-	-	-	-	-	-
21	Electric operating revenues	(166)	-	$0	$0	-	$3 145
22	Fuel used in electric generation						
23	O&M production energy - fuel	-	-	-	-	-	442
24	RECS consumption expense	-	-	-	-	-	-
25	Fuel used in electric generation	-	-	-	-	-	442
26	Purchased power						
27	O&M production purchases - capacity cost	-	-	-	-	-	-
28	O&M production purchases - energy cost	(710)	-	-	-	-	(710)
29	O&M deferred fuel expense	-	-	-	-	-	-
30	Purchased power	(710)	-	-	-	-	(710)
31	Other O&M expense						
32	Labor expense	-	-	-	-	-	(16,290)
33	Pension & benefits	-	-	-	-	-	-
34	Regulatory commission expense	-	-	-	-	-	-
35	Property insurance	-	-	-	-	-	-
36	Injuries & damages - workman's compensation	-	-	-	-	-	-
37	Uncollectible accounts	-	-	-	-	-	-
38	Other O&M expense	2,249	(3,483)	-	(8,065)	-	(29,598)
39	Adjust for other revenue	-	-	-	-	-	-
40	Adjust for non fuel riders/aviation/merger	-	-	-	-	-	-
41	Adjust for non-labor O&M	-	-	-	-	-	-
42	Adjust for rate case expense/reg assets & liabilities	-	-	-	-	-	-
43	Adjust for Severance	-	-	-	-	-	-
44	Adjust for Outside Services	-	-	-	-	-	(146)
45	Adjust for Asheville Plants (Steam & CC) and CertainTeed	-	-	-	-	-	-
46	Other adjustments to regulatory fees and uncollectibles	-	-	-	-	-	-
47	Total Other O&M expenses	2,249	(3,483)	-	(8,065)	-	(46,034)
48	Depreciation | amortization | P&C losses						
49	Depreciation & amortization	(6,209)	-	(2,830)	-	-	(179,767)
50	Adjust other amortization expense	-	-	-	-	-	(30,548)
51	Total depreciation & amortization expense	(6 209)	-	(2 830)	-	-	(210 315)
52	Taxes other than income taxes						
53	Payroll taxes	-	-	-	-	-	-
54	Property taxes	-	-	-	-	-	-
55	Other taxes - federal heavy vehicle use tax	-	-	-	-	-	63
56	Other taxes - electric excise tax - SC	-	-	-	-	-	-
57	Other taxes - privilege tax	-	-	-	-	-	-
58	Miscellaneous taxes - NC	(690)	-	-	-	-	(690)
59	Miscellaneous taxes - SC & other states	-	-	-	-	-	-
60	Other taxes - PUC license tax - SC	-	-	-	-	-	-
61	Adjust costs recovered through non-fuel riders	-	-	-	-	-	-
62	Adjust to reflect retirement of Asheville Steam Generating Plant	-	-	-	-	-	-
63	Total taxes other than income taxes	(690)	-	-	-	-	(627)
64	Interest on customer deposits	-	-	-	-	-	-
65	Income taxes						
66	Federal income taxes	-	-	-	-	-	-
67	State income taxes	-	-	-	-	-	-
68	Income taxes - deferred	-	-	-	-	-	-
69	Adjust NC income taxes for rate change | Synchronize interest						
70	expense	-	-	-	-	-	-
71	Adjust costs recovered through non-fuel riders	-	-	-	-	-	-
72	Adjust for Federal & State income taxes	1,098	807	656	1,869	(1,328)	58,897
73	Total income taxes	1 098	807	656	1 869	(1 328)	58 897
74	Amortization of ITC	34	-	-	-	-	34
75	Total utility operating expenses	(4 228)	(2 676)	(2 174)	(6 196)	(1 328)	(198 313)
76	Interest expense	-	-	-	-	5,733	5,733
77	Income available for common equity 2/	4,062	2,676 -	2,174	6,196	(4,404)	195,725
78	Net operating income for return	4 062	2 676 -	2 174	6 196	1 328	201 458
79	Total requirement	(166)	-	-	-	0	3,145

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY AFTER RATE INCREASE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1(g)
Page 1 of 2

Line No.	Item	Under Present Rates After Adjustments 1/	Lead Lag Days 4/	Iteration 1 Increase	Iteration 1 With Increase 8/	Iteration 1 CWC Change 10/
		(a)	(b)	(c)	(d)	(e)
1	Electric operating revenues:					
2	Rate revenues	$3,282,438	41.88	$383,241 5/	$3,665,679	$43,973
3	Sales for resale revenues	134,915	33.73	-	134,915	-
4	Provisions for rate refunds	(104,546)	41.88	-	(104,546)	-
5	Forfeited discounts	7,664	72.30	-	7,664	-
6	Miscellaneous service revenues	5,506	76.00	-	5,506	-
7	Rent revenues - production plant related	4,466	41.63	-	4,466	-
8	Rent revenues - distribution pole rental revenue	10,901	182.00	-	10,901	-
9	Rent revenues - transmission plant related	382	41.63	-	382	-
10	Rent revenues - additional facilities - wholesale	-	-	-	-	-
11	Rent revenues - additional facilities - ret X lighting	4,617	41.63	-	4,617	-
12	Rent revenues - additional facilities - lighting	3,849	41.63	-	3,849	-
13	Rent revenues - other	3,413	68.21	-	3,413	-
14	Other revenues - production plant related	1,184	41.88	-	1,184	-
15	Other revenues - transmission related	6,208	41.88	-	6,208	-
16	Other revenues - wholesale D/A	368	41.88	-	368	-
17	Other revenues - REPS	1,114	41.88	-	1,114	-
18	Other revenues - other energy	-	-	-	-	-
19	Other revenues - distribution plant related	1,404	41.88	-	1,404	-
20	Other revenues - NC retail specific	271	41.88	-	271	-
21	Electric operating revenues	$3,364,154	42.16	383,241 6/	3,747,395	43,973
22	Fuel used in electric generation:					
23	O&M production energy - fuel	833,586	28.49	-	833,586	-
24	RECS consumption expense	18,522	28.49	-	18,522	-
25	Fuel used in electric generation	852,108	28.49	-	$852,108	-
26	Purchased power:					
27	O&M production purchases - capacity cost	67,280	30.29	-	67,280	-
28	O&M production purchases - energy cost	362,709	30.29	-	362,709	-
29	O&M deferred fuel expense	(273,901)	28.49	-	(273,901)	-
30	Purchased power	156,088	33.45	-	156,088	-
31	Other O&M expense:					
32	Labor expense	391,812	37.07	-	391,812	-
33	Pension & benefits	69,913	13.97	-	69,913	-
34	Regulatory commission expense	6,804	93.25	-	6,804	-
35	Property insurance	(526)	(222.30)	-	(526)	-
36	Injuries & damages - workman's compensation	197	-	-	197	-
37	Uncollectible accounts	8,937	-	-	8,937	-
38	Other O&M expense	503,884	40.52	-	503,884	-
39	Adjust for other revenue	(1,025)	37.32	-	(1,025)	-
40	Adjust for non fuel riders/aviation/merger	(141,634)	37.32	-	(141,634)	-
41	Adjust for non-labor O&M	1,319	33.30	-	1,319	-
42	Adjust for rate case expense/reg assets & liabilities	2,304	-	-	2,304	-
43	Adjust for Severance	(24,140)	37.07	-	(24,140)	-
44	Adjust for Outside Services	(146)	37.07	-	(146)	-
45	Adjust for Asheville Plants (Steam & CC) and CertainTeed	(304)	37.32	-	(304)	-
46	Other adjustments to regulatory fees and uncollectibles			-	-	-
47	Total Other O&M expenses	817,395	37.29	-	817,395	-
48	Depreciation | amortization | P&C losses:					
49	Depreciation & amortization	770,292	-	-	770,292	-
50	Adjust other amortization expense	(30,548)	-	-	(30,548)	-
51	Total depreciation & amortization expense	739,745		-	739,745	-
52	Taxes other than income taxes:					
53	Payroll taxes	25,061	48.41	-	25,061	-
54	Property taxes	77,160	186.50	-	77,160	-
55	Other taxes - federal heavy vehicle use tax	111	-	-	111	-
56	Other taxes - electric excise tax - SC	-	-	-	-	-
57	Other taxes - privilege tax	12,244	(11.97)	-	12,244	-
58	Miscellaneous taxes - NC	(5,207)	60.00	-	(5,207)	-
59	Miscellaneous taxes - SC & other states	1	129.46	-	1	-
60	Other taxes - PUC license tax - SC	-	-	-	-	-
61	Adjust costs recovered through non-fuel riders	(6,458)	137.26	-	(6,458)	-
62	Adjust to reflect retirement of Asheville Steam Generating Plant	(1,032)	186.50	-	(1,032)	-
63	Total taxes other than income taxes	101,880	138.06	-	101,880	-
64	Interest on customer deposits	7,971	137.50	-	7,971	-
65	Income taxes:					
66	Federal income taxes	-	44.75	-	-	-
67	State income taxes	-	44.75	-	-	-
68	Income taxes - deferred	-	-	-	-	-
69	Adjust NC income taxes for rate change | Synchronize interest					
70	expense	(128,708)	20.60	-	(128,708)	-
71	Adjust costs recovered through non-fuel riders	63,168	-	-	63,168	-
72	Adjust for Federal & State income taxes	171,883	20.60	-	171,883	-
73	Total income taxes	106,343	8.36	-	106,343	-
74	Amortization of ITC	(3,581)	-	-	(3,581)	-
75	Total electric operating expenses	2,777,949		-	2,777,949	-
76	Interest expense	214,000	-	-	214,000	-
77	Income available for common equity	176,480	-	293,360 7/	469,840 9/	-
78	Net operating income for return	390,480		293,360	683,840	-
79	Total requirement	$3,168,429		$293,360	$3,461,789	$0
80	Cumulative change in working capital					$43,973
81	Rate base under present rates					10,440,896
82	Rate base after rate increase	$10,440,896 2/				$10,484,869
83	Overall rate of return (L78 / L82)	3.74%				6.52%
84	Target rate of return	6.56% 3/				6.56% 3/

1/ Dorgan Supplemental Exhibit 1, Schedule 2-1(f), Column (e).
2/ Dorgan Supplemental Exhibit 1, Schedule 2, Line 16, Column (c).
3/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 3, Column (h).
4/ Dorgan Supplemental Exhibit 1, Schedule 2-1(f), Column (f).
5/ Line 21 minus (Sum of Line 3 through Line 20).
6/ Line 77 divided by equity retention factor of 0.7654709 from Dorgan Supplemental Exhibit 1, Schedule 1-2, Line 14.
7/ Column (d) minus Column (a).
8/ Column (a) plus Column (c), unless footnoted otherwise..
9/ Line 82, Column (a) multiplied by 50.000% multiplied by 9.000%.
10/ Column (c) divided by 365 days multiplied by Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF WORKING CAPITAL FROM LEAD / LAG STUDY AFTER RATE INCREASE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 2-1(g)

		Iteration 2			Iteration 3			After Increase	
Line No.	Item	Increase	With Increase 12/	CWC Change 16/	Increase	With Increase 19/	CWC Change 23/	Cumulative Increase 24/	After Increase 25/
		(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Electric operating revenues:								
2	Rate revenues	(282,163) 5/	$3,383,516	($32,375)	($2,122) 5/	$3,381,394	($243)	$98,956	$3,381,394
3	Sales for resale revenues	-	134,915	-	-	134,915	-	-	134,915
4	Provisions for rate refunds	-	(104,546)	-	-	(104,546)	-	-	(104,546)
5	Forfeited discounts	-	7,664	-	-	7,664	-	-	7,664
6	Miscellaneous service revenues	-	5,506	-	-	5,506	-	-	5,506
7	Rent revenues - production plant related	-	4,466	-	-	4,466	-	-	4,466
8	Rent revenues - distribution pole rental revenue	-	10,901	-	-	10,901	-	-	10,901
9	Rent revenues - transmission plant related	-	382	-	-	382	-	-	382
10	Rent revenues - additional facilities - wholesale	-	-	-	-	-	-	-	-
11	Rent revenues - additional facilities - ret X lighting	-	4,617	-	-	4,617	-	-	4,617
12	Rent revenues - additional facilities - lighting	-	3,849	-	-	3,849	-	-	3,849
13	Rent revenues - other	-	3,413	-	-	3,413	-	-	3,413
14	Other revenues - production plant related	-	1,184	-	-	1,184	-	-	1,184
15	Other revenues - transmission related	-	6,208	-	-	6,208	-	-	6,208
16	Other revenues - wholesale D/A	-	368	-	-	368	-	-	368
17	Other revenues - REPS	-	1,114	-	-	1,114	-	-	1,114
18	Other revenues - other energy	-	-	-	-	-	-	-	-
19	Other revenues - distribution plant related	-	1,404	-	-	1,404	-	-	1,404
20	Other revenues - NC retail specific	-	271	-	-	271	-	-	271
21	Electric operating revenues	(282,163) 11/	3,465,232 13/	(32,375)	(2,122) 17/	3,463,110 20/	(243)	98,956	$3,463,110
22	Fuel used in electric generation:								
23	O&M production energy - fuel	-	833,586	-	-	833,586	-	-	833,586
24	RECS consumption expense	-	18,522	-	-	18,522	-	-	18,522
25	Fuel used in electric generation	-	852,108	-	-	852,108	-	-	852,108
26	Purchased power:								
27	O&M production purchases - capacity cost	-	67,280	-	-	67,280	-	-	67,280
28	O&M production purchases - energy cost	-	362,709	-	-	362,709	-	-	362,709
29	O&M deferred fuel expense	-	(273,901)	-	-	(273,901)	-	-	(273,901)
30	Purchased power	-	156,088	-	-	156,088	-	-	156,088
31	Other O&M expense:								
32	Labor expense	-	391,812	-	-	391,812	-	-	391,812
33	Pension & benefits	-	69,913	-	-	69,913	-	-	69,913
34	Regulatory commission expense	-	6,804	-	-	6,804	-	-	6,804
35	Property insurance	-	(526)	-	-	(526)	-	-	(526)
36	Injuries & damages - workman's compensation	-	197	-	-	197	-	-	197
37	Uncollectible accounts	-	8,937	-	-	8,937	-	-	8,937
38	Other O&M expense	-	503,884	-	-	503,884	-	-	503,884
39	Adjust for other revenue	-	(1,025)	-	-	(1,025)	-	-	(1,025)
40	Adjust for non fuel riders/aviation/merger	-	(141,634)	-	-	(141,634)	-	-	(141,634)
41	Adjust for non-labor O&M	-	1,319	-	-	1,319	-	-	1,319
42	Adjust for rate case expense/reg assets & liabilities	-	2,304	-	-	2,304	-	-	2,304
43	Adjust for Severance	-	(24,140)	-	-	(24,140)	-	-	(24,140)
44	Adjust for Outside Services	-	(146)	-	-	(146)	-	-	(146)
45	Adjust for Asheville Plants (Steam & CC) and CertainTeed	-	(304)	-	-	(304)	-	-	(304)
46	Other adjustments to regulatory fees and uncollectibles	-	-	-	-	-	-	-	-
47	Total Other O&M expenses	-	817,395	-	-	817,395	-	-	817,395
48	Depreciation | amortization | P&C losses:								
49	Depreciation & amortization	-	770,292	-	-	770,292	-	-	770,292
50	Adjust other amortization expense	-	(30,548)	-	-	(30,548)	-	-	(30,548)
51	Total depreciation & amortization expense	-	739,745	-	-	739,745	-	-	739,745
52	Taxes other than income taxes:								
53	Payroll taxes	-	25,061	-	-	25,061	-	-	25,061
54	Property taxes	-	77,160	-	-	77,160	-	-	77,160
55	Other taxes - federal heavy vehicle use tax	-	111	-	-	111	-	-	111
56	Other taxes - electric excise tax - SC	-	-	-	-	-	-	-	-
57	Other taxes - privilege tax	-	12,244	-	-	12,244	-	-	12,244
58	Miscellaneous taxes - NC	-	(5,207)	-	-	(5,207)	-	-	(5,207)
59	Miscellaneous taxes - SC & other states	-	1	-	-	1	-	-	1
60	Other taxes - PUC license tax - SC	-	-	-	-	-	-	-	-
61	Adjust costs recovered through non-fuel riders	-	(6,458)	-	-	(6,458)	-	-	(6,458)
62	Adjust to reflect retirement of Asheville Steam Generating Plant	-	(1,032)	-	-	(1,032)	-	-	(1,032)
63	Total taxes other than income taxes	-	101,880	-	-	101,880	-	-	101,880
64	Interest on customer deposits	-	7,971	-	-	7,971	-	-	7,971
65	Income taxes:								
66	Federal income taxes	-	-	-	-	-	-	-	-
67	State income taxes	-	-	-	-	-	-	-	-
68	Income taxes - deferred	-	-	-	-	-	-	-	-
69	Adjust NC income taxes for rate change | Synchronize interest		-			-			-
70	expense	-	(128,708)	-	-	(128,708)	-	-	(128,708)
71	Adjust costs recovered through non-fuel riders	-	63,168	-	-	63,168	-	-	63,168
72	Adjust for Federal & State income taxes	-	171,883	-	-	171,883	-	-	171,883
73	Total income taxes	-	106,343	-	-	106,343	-	-	106,343
74	Amortization of ITC	-	(3,581)	-	-	(3,581)	-	-	(3,581)
75	Total electric operating expenses	-	2,777,949	-	-	2,777,949	-	-	2,777,949
76	Interest expense	1,464 11/	215,464 14/	-	(665) 18/	214,799 21/	-	799	214,799
77	Income available for common equity	1,979 11/	471,819 15/	-	(1,457) 18/	470,362 22/	-	293,882	470,362
78	Net operating income for return	3,443	687,283	-	(2,122)	685,161	-	294,681	685,161
79	Total requirement	3,443	3,465,232	-	(2,122)	3,463,110	-	294,681	3,463,110
80	Cumulative change in working capital			$11,598			$11,355		$11,355
81	Rate base under present rates			10,440,896			10,440,896		10,440,896
82	Rate base after rate increase			$10,452,494			$10,452,251		$10,452,251
83	Overall rate of return (L78 / L82)			6.58%			6.56%		6.56%
84	Target rate of return			6.56% 3/			6.56% 3/		6.56% 3/

11/ Column (g) minus Column (d).
12/ Column (d) plus Column (f), unless footnoted otherwise.
13/ Column (g), Line 79.
14/ Line 82, Column (e) multiplied by 50.000% multiplied by 4.110%.
15/ Line 82, Column (e) multiplied by 50.000% multiplied by 9.000%.
16/ Column (f) divided by 365 days multiplied by Column (b).
17/ Column (j) minus Column (g).
18/ Column (j) minus Column (g).
19/ Column (g) plus Column (i), unless footnoted otherwise.
20/ Column (j), Line 79.
21/ Line 82, Column (h) multiplied by 50.000% multiplied by 4.110%.
22/ Line 82, Column (h) multiplied by 50.000% multiplied by 9.000%.
23/ Column (i) divided by 365 days multiplied by Column (b).
24/ Column (c) plus Column (f) plus Column (i).
25/ Column (a) plus Column (l), unless footnoted otherwise.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
NET OPERATING INCOME FOR RETURN
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3

		Under Present Rates			After Public Staff Recommended Increase	
Line No.		NC Retail Adjusted Per Company 1/	Public Staff Adjustments 2/	After Public Staff Adjustments 3/	Rate Increase	After Rate Increase 7/
		(a)	(b)	(c)	(d)	(e)
1	Electric operating revenues:					
2	Sales of electricity	$ 3,361,009	$3,145	$3,364,154	$129,014 4/	$3,493,168
3	Other revenues	-	-	-	-	-
4	Electric operating revenues (Sum of L2 through L3)	$3,361,009	$3,145	$3,364,154	$129,014	$3,493,168
5	Electric operating expenses:					
6	Operations and maintenance:					
7	Fuel used in electric generation	851,667	442	852,109	-	852,109
8	Purchased power	156,798	(710)	156,088	-	156,088
9	Other operations and maintenance expenses	863,429	(46,034)	817,395	476 5/	817,871
10	Depreciation and amortization	950,060	(179,767)	770,293	-	770,293
11	General taxes	102,506	(627)	101,879	-	101,879
12	Interest on customer deposits	7,971	-	7,971	-	7,971
13	Net income taxes	47,541	51,593	99,134	29,727 6/	128,861
14	Amortization of protected EDIT, net of tax	-	(23,470)	(23,470)	-	(23,470)
15	Amortization of investment tax credit	(3,614)	34	(3,580)	-	(3,580)
16	Total electric operating expenses (Sum of L6 through L15)	2,976,358	(198,539)	2,777,819	30,203	2,808,022
17	Net operating income for return (L4 minus L16)	$384,651	$201,683	$586,334	$98,811	$685,145

1/ Based on updated Smith Supplemental Exhibit 1.
2/ Dorgan Supplemental Exhibit 1, Schedule 3-1, Column (ad).
3/ Column (a) plus Column (b).
4/ Dorgan Supplemental Exhibit 1, Schedule 5, Line 5, Column (c).
5/ Line 4 times (1 minus retention factor after uncollectibles and regulatory fee of 0.9963091 from Dorgan Supplemental Exhibit 1, Schedule 1-2, Line 10).
6/ (Line 4 minus Line 9) minus (increase in debt expense from Dorgan Supplemental Exhibit 1, Schedule 5, Line 5, Column (a) multiplied by composite income tax rate of 23.1693%).
7/ Column (c) plus Column (d).

I/A

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1

Line No.	Item	Update Plant to 2/29/2020	Update Revenues/ Customer Growth/ Weather to 2/29/2020	Adjust Credit Card Fees	Remove EDIT Refunds for Treatment as Riders	Include Flowback of Protected EDIT due to Tax Cuts & Jobs Act	Adjust Depreciation Rates	Adjust Salaries & Wages
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Electric operating revenues:							
2	Sales of electricity	$0	$3,311 4/	$0	$0	$0	$0	$0
3	Other revenues	-	-	-	-	-	-	-
4	Electric operating revenues (Sum of L2 through L3)	-	3,311	-	-	-	-	-
5	Electric operating expenses:							
6	Operations and maintenance:							
7	Fuel used in electric generation	-	442 4/	-	-	-	-	-
8	Purchased power	-	-	-	-	-	-	-
9	Other operations and maintenance expenses	-	(4,532) 4/	(95) 5/	-	-	-	- 8/
10	Depreciation and amortization	(224) 3/	-	-	-	- 6/	(42,779) 7/	-
11	General taxes	65 3/	-	-	-	-	-	- 8/
12	Interest on customer deposits	-	-	-	-	-	-	-
13	Net income taxes	37 2/	1,715 2/	22 2/	-	- 2/	9,912 2/	- 2/
14	Amortization of protected EDIT, net of tax	-	-	-	-	(23,470)	-	-
15	Amortization of investment tax credit	-	-	-	-	-	-	-
16	Total electric operating expenses (Sum of L6 through L15)	(122)	(2,375)	(73)	-	(23,470)	(32,867)	-
17	Net operating income for return (L4 minus L16)	122	5,686	73	-	23,470	32,867	-
18	Calculated revenue requirement impact 1/	($160)	($7,428)	($95)	$0	($30,660)	($42,936)	$0

1/ Negative of Line 16 divided by equity retention factor 0.7635890 from Dorgan Supplemental Exhibit 1, Schedule 1-2, Line 14.
2/ Line 4 minus Sum of Lines 7 through 12 times composite income tax rate of 23.1693%.
3/ Dorgan Supplemental Exhibit 1, Schedule 3-1(a).
4/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b).
5/ Dorgan Supplemental Exhibit 1, Schedule 3-1(c).
6/ Dorgan Supplemental Exhibit 1, Schedule 3-1(d).
7/ Dorgan Supplemental Exhibit 1, Schedule 3-1(e).
8/ Dorgan Supplemental Exhibit 1, Schedule 3-1(f).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1
Page 2 of 4

Line No.	Item		Adjust Incentives		Adjust Severance Costs		Adjust Executive Compensation		Adjust Aviation Expenses		Adjust Outside Services		Adjust to Normalize Storm Costs		Adjust Storm Deferral	
			(h)		(i)		(j)		(k)		(l)		(m)		(n)	
1	Electric operating revenues:															
2	Sales of electricity		$0		$0		$0		$0		$0		$0		$0	
3	Other revenues		-		-		-		-		-		-		-	
4	Electric operating revenues (Sum of L2 through L3)		-		-		-		-		-		-		-	
5	Electric operating expenses:															
6	Operations and maintenance:															
7	Fuel used in electric generation		-		-		-		-		-		-		-	
8	Purchased power		-		-		-		-		-		-		-	
9	Other operations and maintenance expenses		(14,652)	9/	(4,331)	10/	(160)	11/	(405)	12/	(146)	13/	9,300	14/	-	
10	Depreciation and amortization		-		-		-		-		-		-		(44,793)	15/
11	General taxes		-		-		-		(2)	12/	-		-		-	
12	Interest on customer deposits		-		-		-		-		-		-		-	
13	Net income taxes		3,395	2/	1,003	2/	37	2/	94	2/	34	2/	(2,155)	2/	10,378	2/
14	Amortization of protected EDIT, net of tax		-		-		-		-		-		-		-	
15	Amortization of investment tax credit		-		-		-		-		-		-		-	
16	Total electric operating expenses (Sum of L6 through L15)		(11,257)		(3,328)		(123)		(313)		(112)		7,145		(34,415)	
17	Net operating income for return (L4 minus L16)		11,257		3,328		123		313		112		(7,145)		34,415	
18	Calculated revenue requirement impact	1/	($14,705)		($4,347)		($161)		($409)		($146)		$9,334		($44,960)	

9/ Dorgan Supplemental Exhibit 1, Schedule 3-1(g).
10/ Dorgan Supplemental Exhibit 1, Schedule 3-1(h).
11/ Dorgan Supplemental Exhibit 1, Schedule 3-1(i).
12/ Dorgan Supplemental Exhibit 1, Schedule 3-1(j).
13/ Dorgan Supplemental Exhibit 1, Schedule 3-1(k).
14/ Dorgan Supplemental Exhibit 1, Schedule 3-1(l).
15/ Dorgan Supplemental Exhibit 1, Schedule 3-1(m).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1

Line No.	Item		Adjust Charitable Contributions, and Corporate Sponsorships & Donations		Adjust Lobbying Expense		Adjust Board of Directors Expense		Adjust EOL Nuclear M&S Reserve Amortization		Adjustment to Remove Deferred Environmental Costs - ARO		Adjustment to Remove Deferred Non-ARO Environmental Costs		Adjustment to Remove CertainTeed Payment Obligation		Adjustment to Inflation Adjustment	
			(o)		(p)		(q)		(r)		(s)		(t)		(u)		(v)	
1	Electric operating revenues:																	
2	Sales of electricity		$0		$0		$0		$0		$0		$0		$0		$0	
3	Other revenues		-		-		-		-		-		-		-		-	
4	Electric operating revenues (Sum of L2 through L3)		-		-		-		-		-		-		-		-	
5	Electric operating expenses:																	
6	Operations and maintenance:																	
7	Fuel used in electric generation		-		-		-		-		-		-		-		-	
8	Purchased power		-		-		-		-		-		-		-		-	
9	Other operations and maintenance expenses		(36)	16/	(1,538)	17/	(1,270)	18/	-		-		-		(4,939)	21/	2,799	22/
10	Depreciation and amortization		-		-		-		(1,807)	19/	(77,167)	20/	(3,958)	20/	-		-	
11	General taxes		-		-		-		-		-		-		-		-	
12	Interest on customer deposits		-		-		-		-		-		-		-		-	
13	Net income taxes		8	2/	356	2/	294	2/	419	2/	17,879		917		1,144	2/	(648)	2/
14	Amortization of protected EDIT, net of tax		-		-		-		-		-		-		-		-	
15	Amortization of investment tax credit		-		-		-		-		-		-		-		-	
16	Total electric operating expenses (Sum of L6 through L15)		(28)		(1,182)		(976)		(1,388)		(59,288)		(3,041)		(3,795)		2,151	
17	Net operating income for return (L4 minus L16)		28		1,182		976		1,388		59,288		3,041		3,795		(2,151)	
18	Calculated revenue requirement impact	1/	($37)		($1,544)		($1,275)		($1,813)		($77,453)		($3,973)		($4,958)		$2,810	

16/ Dorgan Supplemental Exhibit 1, Schedule 3-1(n).
17/ Dorgan Supplemental Exhibit 1, Schedule 3-1(o).
18/ Dorgan Supplemental Exhibit 1, Schedule 3-1(p).
19/ Dorgan Supplemental Exhibit 1, Schedule 3-1(q).
20/ Based on recommendation of Public Staff witness Maness.
21/ Moved to fuel case docket per NCUC order (Docket E-2, Sub 1204).
22/ Dorgan Supplemental Exhibit 1, Schedule 3-1(v).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
SUMMARY OF PUBLIC STAFF NET OPERATING INCOME ADJUSTMENTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1

Line No.	Item		Adjustment to Nuclear Decommissioning Expense		Adjustment to Remove Rate Case Expense		Adjustment to COSS - SWP&A Reallocation		Adjust Asheville CC Plant in Service Costs		Adjust Asheville CC Deferral		Adjust for Asheville Production Displacement		Interest Synchronization Adjustment		Total NOI Adjustments 30/
			(w)		(x)		(y)		(z)		(aa)		(ab)		(ac)		(ad)
1	Electric operating revenues:																
2	Sales of electricity		$0		$0		($166)		$0		$0		$0		$0		$3,145
3	Other revenues		-		-		-		-		-		-		-		-
4	Electric operating revenues (Sum of L2 through L3)		-		-		(166)		-		-		-		-		3,145
5	Electric operating expenses:																
6	Operations and maintenance:																
7	Fuel used in electric generation		-		-		-		-		-		-		-		442
8	Purchased power		-		-		(710)	25/	-		-		-		-		(710)
9	Other operations and maintenance expenses		(16,537)	23/	(193)	24/	2,249	25/	(3,483)	26/	-		(8,065)	28/	-		(46,034)
10	Depreciation and amortization		-		-		(6,209)	25/	-		(2,830)	27/	-		-		(179,767)
11	General taxes		-		-		(690)	25/	-		-		-		-		(627)
12	Interest on customer deposits		-		-		-		-		-		-		-		-
13	Net income taxes		3,831	2/	45	2/	1,098	25/	807	2/	656	2/	1,869	2/	(1,554)	29/	51,593
14	Amortization of protected EDIT, net of tax		-		-		-		-		-		-		-		(23,470)
15	Amortization of investment tax credit		-		-		34	25/	-		-		-		-		34
16	Total electric operating expenses (Sum of L6 through L15)		(12,706)		(148)		(4,228)		(2,676)		(2,174)		(6,196)		(1,554)		(198,539)
17	Net operating income for return (L4 minus L16)		12,706		148		4,062		2,676		2,174		6,196		1,554		201,683
18	Calculated revenue requirement impact	1/	($16,599)		($194)		($5,307)		($3,496)		($2,840)		($8,095)		($2,030)		($263,476)

23/ Per Recommendation of Public Staff witness Hinton.
24/ Dorgan Supplemental Exhibit 1, Schedule 3-1(r).
25/ Dorgan Supplemental Exhibit 1, Schedule 3-1(s).
26/ Dorgan Supplemental Exhibit 1, Schedule 3-1(t).
27/ Dorgan Supplemental Exhibit 1, Schedule 3-1(t)(1).
28/ Dorgan Supplemental Exhibit 1, Schedule 3-1(u).
29/ Dorgan Supplemental Exhibit 1, Schedule 3-1(w).
30/ Sum of Columns (a) through Column (ad).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO DEPRECIATION EXPENSE AND PROPERTY TAXES FOR PLANT UPDATE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(a)

Line No.	Item	Amount	
1	**Depreciation expense**		
2	Depreciation expense on increase in plant per Public Staff	$61,158	1/
3	Company Adjustment	61,382	2/
4	Public Staff adjustment to depreciation expense for update of plant (L2 - L3)	($224)	
5	**General taxes**		
6	Update to plant per Public Staff	$1,434,886	3/
7	Less: Adjustment to intangible plant	57,105	4/
8	Adjustment to plant excluding intangible plant (L6 - L7)	$1,377,781	
9	Average property tax rate	0.36259%	5/
10	Impact to property taxes of Public Staff update (L8 x L9)	$4,996	
11	Company Adjustment per Application/Update	4,931	6/
12	Public Staff adjustment to property taxes (L10 - L11)	$65	

1/ Dorgan Supplemental Exhibit 1, Schedule 3-1(a)(1), Line 20, Column (e).
2/ NCUC Form E-1, Item No. 10, NC-1001, Page 2, Line 78 (Total NC Retail column), as adjusted to SWPA.
3/ Dorgan Supplemental Exhibit 1, Schedule 2-1(a)(1), Line 11, Column (g).
4/ Dorgan Supplemental Exhibit 1, Schedule 2-1(a)(1), Line 10, Column (g).
5/ NCUC Form E-1, Item No. 10, NC-1001, Line 83.
6/ NCUC Form E-1, Item No. 10, NC-1001, Page 2, Line 90 minus Line 86, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF DEPRECIATION EXPENSE ON PLANT UPDATE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(a)(1)

Line No.	Item	Increase in Plant in Service 1/	Depreciation Rate 2/	Increase in Depreciation 4/	NC Retail Percentage 5/	NC Retail Amount 6/
		(a)	(b)	(c)	(d)	(e)
1	Steam plant	($192,169)	4.13%	($7,937)	60.8591%	($4,830)
2	Direct Assignment - NC steam production	134	4.13%	6	100.0000%	6
3	Direct Assignment - SC steam production	0	4.13%	-	0.0000%	-
4	Direct Assignment - WSH steam production	(4,614)	4.13%	(191)	0.0000%	-
5	Hydro plant	13,247	3.65%	484	60.8591%	295
6	Other production plant	831,077	5.03%	41,803	60.8591%	25,441
7	Direct Assignment - NC other production	0	5.03%	-	100.0000%	-
8	Direct Assignment - SC other production	0	5.03%	-	0.0000%	-
9	Direct Assignment - WSH other production	(300)	5.03%	(15)	0.0000%	-
10	Nuclear plant	330,067	3.31%	10,925	60.8591%	6,649
11	Direct Assignment - NC nuclear production	2,934	3.31%	97	100.0000%	97
12	Direct Assignment - SC nuclear production	352	3.31%	12	0.0000%	-
13	Direct Assignment - WSH nuclear production	368	3.31%	12	0.0000%	-
14	Total production plant	$981,095		$45,196		
15	Transmission plant	264,107	2.23%	5,890	58.8448%	3,466
16	Distribution plant	692,508	2.26%	15,651	87.1486%	13,640
17	Distribution plant - AMR meter retirements	(61,039)				
18	General plant	77,411	4.39%	3,398	73.7686%	2,507
19	Intangible plant	105,665	various 3/	20,607	67.3953%	13,888
20	Total	$2,059,747		$90,742		$61,158

1/ Dorgan Exhibit 1, Schedule 2-1(a)(1), Column (e).
2/ Based on recommendation of Public Staff witness McCullar, unless footnoted otherwise.
3/ Based on information provided by the Company.
4/ Column (a) times Column (b).
5/ NCUC Form E-1, Item No. 45B.
6/ Column (c) multiplied by Column (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO UPDATE REVENUES TO FEBRUARY 29, 2020
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(b)

Line No.	Item	Adjustment	
	Revenues		
1	Update revenues for customer growth	$64,452	1/
2	Update revenues for usage	(61,464)	2/
3	Update revenues for weather	323	3/
4	Adjust revenues for update (L1 + L2 + L3)	$3,311	
	Fuel and Fuel Related Expense		
5	Adjust fuel and fuel-related expense for customer growth update	$17,904	1/
6	Adjust fuel and fuel-related expense for usage update	(17,618)	2/
7	Adjust fuel and fuel-related expense for weather update	156	3/
8	Adjust fuel expense for change in kWh (L5 + L6 + L7)	$442	
	Other O&M Expense		
9	Public Staff update adjustment to mWh sales for customer growth (kWh/1000)	655,895	1/
10	Public Staff update adjustment to mWh sales for customer usage (kWh/1000)	(731,113)	2/
11	Public Staff update adjustment to mWh sales for weather (kWh/1000)	(858,188)	3/
12	Public Staff adjustment to mWh sales (kWh/1000) (L9 + L10 + L11)	(933,407)	
13	Energy-related non-fuel variable O&M expense (in dollars per mWh)	5.82786	4/
14	Adjustment to energy-related non-fuel variable O&M expense (L12 x L13 / 1000)	($5,440)	
15	Public Staff change in bills	415,178	5/
16	Annual customer-related variable O&M expense per bill (in dollars)	2.15793	6/
17	Adjustment to customer-related variable O&M expense (L14 x L15 / 1,000)	$896	
18	Adjust variable non-fuel O&M expense (L14 + L17)	($4,544)	
19	Adjust uncollectibles for increase in revenues	8	7/
20	Adjust regulatory fee for increase in revenues, net of uncollectibles	4	8/
21	Total adjustment to other O&M expenses (L18 + L19 + L20)	($4,532)	

1/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b)(1), Line 21.
2/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b)(2), Line 20.
3/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b)(4), Line 7.
4/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b)(3), Line 24.
5/ Based on the recommendation of Public Staff witness Saillor.
6/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b)(5), Line 19.
7/ Line 4 times uncollectibles rate of 0.2394%.
8/ (Line 4 minus Line 19) multiplied by regulatory fee rate of 0.13%.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ADJUSTMENT TO REVENUES AND FUEL RELATED EXPENSES TO UPDATE CUSTOMER GROWTH TO FEBRUARY 29, 2020
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(b)(1)

		Revenues				
Line No.	Item	Public Staff Growth in NC KWH Adjustment 1/	Cents per KWH 2/	Public Staff Adjustment 3/	Fuel Costs in Cents per KWH 4/	Public Staff Adjustment 5/
		(a)	(b)	(c)	(d)	(e)
1	Residential (excluding TOU)	446,610,250	8.85	$39,529	2.3260	$10,388
2	Residential TOU	8,703,408	8.70	757	2.3260	202
3	BCF Revenues			5,658		
4	Total NC Residential Service (sum of L 1 thru L3)	455,313,658		$45,944		$10,590
5	SGS (excluding Constant Load Rate)	28,621,309	10.81	$3,095	2.4990	$715
6	SGS Constant Load Rate	1,074,850	11.20	120	2.4990	27
7	Total NC Small General Service (L5 + L6)	29,696,159		$3,215		$742
8	Medium General Service (excluding Time of Use)	61,472,997	8.73	$5,368	2.4560	$1,510
9	SGS Time of Use	81,504,976	6.72	5,480	2.4560	2,002
10	Seasonal and Intermittent Service	3,141,764	10.95	344	2.4560	77
11	Total NC Medium General Service (L7+ L8 + L9)	146,119,738		$11,192		$3,589
12	LGS (excluding TOU and RTP)	6,988,823	6.92	$484	2.0540	$144
13	LGS Time of Use	9,609,632	6.29	605	2.0540	197
14	LGS Real Time Pricing	6,512,313	5.08	331	2.0540	134
15	Total NC Large General Service (L11+ L12 + L13)	23,110,768		$1,420		$475
16	Street Lighting Service	1,677,242	30.84	$517	2.2170	$37
17	Traffic Signal Lighting Service	(103,515)	9.15	(9)	2.2170	(2)
18	Sports Field Lighting Service	80,635	17.81	14	2.2170	2
19	Total Area and Outdoors Lighting - NC Retail (L15 + L16 + L17)	1,654,362		$522		$37
20	Total NC Retail (L3 + L6 + L10 + L14 + L18)	655,894,685		$62,293		$15,433
21	Company Adjustments			(2,159) 6/		(2,471) 7/
22	Public Staff adjustment to revenues			$64,452		$17,904

1/ Amounts per Public Staff witness Saillor.
2/ NCUC Form E-1, Item No. 10, NC-0402(E), Column (b).
3/ (Column (a) times Column (b)) divided by 100,000.
4/ NCUC Form E-1, Item No. 10, NC-0401(E), Line 4.
5/ (Column (a) times Column (d)) divided by 100,000.
6/ NCUC Form E-1, Item No. 10, NC-0401(E), Line 2, Total NC Retail Column, as adjusted to SWPA.
7/ NCUC Form E-1, Item No. 10, NC-0401(E), Line 6, Total NC Retail Column, as adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ADJUSTMENT TO REVENUES AND FUEL RELATED EXPENSES TO UPDATE CUSTOMER USAGE TO FEBRUARY 29, 2020
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(b)(2)

Line No.	Item	Revenues: Public Staff Usage in NC KWH Adjustment 1/ (a)	Revenues: Cents per KWH 2/ (b)	Revenues: Public Staff Adjustment 3/ (c)	Fuel Costs in Cents per KWH 4/ (d)	Public Staff Adjustment 5/ (e)
1	Residential (excluding TOU)	(381,918,196)	8.85	($33,803)	2.3260	($8,883)
2	Residential TOU	(7,442,708)	8.70	(647)	2.3260	(173)
3	Total NC Residential Service (L1 + L2)	(389,360,904)		($34,450)		($9,056)
4	SGS (excluding Constant Load Rate)	(75,526,849)	8.76	($6,614)	2.4990	($1,887)
5	SGS Constant Load Rate	(2,836,350)	6.39	(181)	2.4990	(71)
6	Total NC Small General Service (L4 + L5)	(78,363,199)		($6,795)		($1,958)
7	Medium General Service (excluding Time of Use)	(124,868,375)	8.53	($10,651)	2.4560	($3,067)
8	SGS Time of Use	(165,558,772)	6.61	(10,952)	2.4560	(4,066)
9	Seasonal and Intermittent Service	(6,381,778)	10.42	(665)	2.4560	(157)
10	Total NC Medium General Service (L7+ L8 + L9)	(296,808,924)		($22,268)		($7,290)
11	LGS (excluding TOU and RTP)	10,097,727	6.90	$697	2.0540	$207
12	LGS Time of Use	13,884,375	6.26	870	2.0540	285
13	LGS Real Time Pricing	9,409,246	5.08	478	2.0540	193
14	Total NC Large General Service (L11+ L12 + L13)	33,391,348		$2,045		$685
15	Total NC General (L3 + L6 + L10 + L14)	(731,141,680)		($61,468)		($17,619)
16	Street Lighting Service	-	15.46	-	2.2170	-
17	Traffic Signal Lighting Service	-	9.15	-	2.2170	-
18	Sports Field Lighting Service	28,533	15.46	4	2.2170	1
19	Total NC Street Lighting (L15 + L16 + L17)	28,533		4		1
20	Total NC Retail (L15 + L19)	(731,113,146)		($61,464)		($17,618)

1/ Amounts per Public Staff witness Saillor.
2/ NCUC Form E-1, Item No. 10, NC-0402(E), Column (b).
3/ (Column (a) multiplied by Column (b)) divided by 100,000.
4/ NCUC Form E-1, Item No. 10, NC-0401(E), Line 4.
5/ (Column (a) multiplied by Column (d)) divided by 100,000.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF VARIABLE NON-FUEL O&M EXPENSE PER MWH
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(b)(3)

Line No.	Item	NC Retail Amount (a)		Sub-Calculations (b)	
1	2018 per books energy-related production O&M expense excluding fuel and purchased power	$346,881	1/		
2	Non-fuel rider energy-related costs removed from base rates	(135,418)	2/		
3	Total non-fuel, non-payroll energy related production O&M expense (L1 - L2)	$211,463			
4	Total O&M expense, excluding A&G expense	2,816,946	3/		
5	Less: fuel expense	1,115,110	4/		
6	Total non-fuel O&M expense, excluding A&G expense (L4 - L5)	1,701,836			
7	Ratio (L3 / L6)	0.124256			
8	Total per books A&G expense	$302,537	5/		
9	Salaries and wages - system amount			$144,924	6/
10	Per books employee pensions and benefits - system amount			133,210	7/
11	Subtotal (L9 + L10)			$278,134	
12	NC Retail Allocation Factor			65.8950%	8/
13	NC retail per books - salaries, wages, pensions, and employee benefits (L11 x L12)			$183,276	
14	Aviation expense removed elsewhere			1,857	9/
15	NC regulatory fee adjusted elsewhere			3,274	10/
16	Outside services removed elsewhere			146	11/
17	Sponsorships and donations removed elsewhere			36	12/
18	Board of Directors expense removed elsewhere			1,270	13/
19	Total of A&G items adjusted elsewhere (Sum of Lines 13 through L18)	189,859		$189,859	
20	Total A&G expense not adjusted elsewhere (L8 - L18)	$112,678			
21	Portion of A&G not adjusted elsewhere related to non-fuel non-payroll energy-related production O&M expense (L7 x L20)	14,001			
22	Total non-fuel, non-payroll energy-related production O&M expense plus related non-payroll A&G expense (L3 + L21)	$225,464			
23	Per books NC retail mWh sales	38,687,268	14/		
24	Cost per mWh (in dollars) (L22 x 1,000 / L23)	$5.82786			

1/ NCUC Form E-1, Item No. 45B, SWPA, Total Production O&M-Energy.
2/ NCUC Form E-1, Item No. 10, NC-0601, Other O&M expense excluding Line 23, Total NC Retail Column, adjusted to SWPA.
3/ NCUC Form E-1, Item No. 45B, SWPA, NC Retail Column, O&M expenses, Total of Tab 1.
4/ NCUC Form E-1, Item No. 10, NC-0201, Total NC Retail Column, Sum of Lines 2, 4, and 5; adjusted to SWPA.
5/ NCUC Form E-1, Item No. 45B, SWPA, A&G expenses, Tab 2.
6/ NCUC Form E-1, Item No. 10, NC-1306, Line 27.
7/ NCUC Form E-1, Item No. 10, NC-1309, Line 6.
8/ NC Retail Allocation Factor: SWPA - LAB (labor).
9/ NCUC Form E-1, Item No. 10, NC-1701, Line 2 plus Dorgan Supplemental Exhibit 1, Schedule 3-1(m), Line 9 plus Line 21.
10/ NCUC Form E-1, Item 10, NC-3101, Line 7.
11/ Dorgan Supplemental Exhibit 1, Schedule 3-1(k), Line 6.
12/ Dorgan Supplemental Exhibit 1, Schedule 3-1(n), Line 6.
13/ Dorgan Supplemental Exhibit 1, Schedule 3-1(p), Line 15.
14/ NCUC Form E-1, Item No. 10, NC-0201, Line 15 divided by 1,000.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ADJUSTMENT TO TEST YEAR REVENUES AND FUEL RELATED EXPENSES FOR WEATHER
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(b)(4)

		Revenues			Fuel & Fuel Related Expenses	
Line No.	Item	Public Staff NC kWh Weather Adjustment 1/	Cents per kWh 2/	Public Staff Adjustment 3/	Fuel Costs in Cents per kWh 4/	Public Staff Adjustment 5/
		(a)	(b)	(c)	(d)	(e)
1	Total NC Residential	(626,372,114)	8.8115	($55,193)	2.3260	($14,569)
2	Total NC Small General Service	(34,111,482)	8.7198	(2,974)	2.4990	(852)
3	Total NC Medium General Service	(197,377,245)	7.0942	(14,002)	2.4560	(4,848)
4	Total NC Large General Service	(327,342)	5.5487	(18)	2.0540	(7)
5	Total NC Retail (L1 + L2 + L3 + L4)			($72,187)		($20,276)
6	Company Adjustment			(72,510) 6/		(20,432) 7/
7	Public Staff adjustment to revenues (L5 - L6)	(858,188,182)		$323		$156

1/ Amounts per Public Staff witness Saillor.
2/ NCUC Form E-1, Item No. 10, NC-0301(E), Line 10.
3/ (Column (a) multiplied by Column (b)) divided by 100,000.
4/ NCUC Form E-1, Item No. 10, NC-0301(E), Line 14.
5/ (Column (a) multiplied by Column (d)) divided by 100,000.
6/ NCUC Form E-1, Item No. 10, NC-0301(E), Line 7, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF BILL-RELATED EXPENSES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(b)(5)

Line No.	Item	NC Retail Amount (a)		Sub-Calculations (b)	
1	2018 per books bill-related O&M expenses:				
2	Account 586 - Meters (operation)	$6,592	1/		
3	Account 587 - Customer - installations	4,525	1/		
4	Accounts 901-905 - Customer accounts	49,620	2/		
5	Accounts 908-910 - Customer service and information	3,202	2/		
6	Total 2018 per books bill-related expenses (Sum of Lines 2 through 5)	$63,939			
7	Salaries and wages included in Line 6 - system amount			30,686	3/
8	NC Retail Allocation Factor			65.8950%	4/
9	NC retail salaries and wages included in Line 7 (L7 x L8)	20,221		$20,221	
10	Uncollectibles expense adjusted elsewhere	8,937	5/		
11	Total non-payroll bill-related O&M expenses not adjusted elsewhere (L6 - L9 - L10)	$34,781			
12	Total O&M expense, excluding A&G expense	2,816,946	6/		
13	Total non-fuel O&M expense, excluding A&G expense	1,701,836	7/		
14	Ratio (L11 / L13)	0.020437			
15	Total A&G expense not adjusted elsewhere	$112,678	8/		
16	Portion of A&G not adjusted elsewhere related to non-payroll bill-related O&M expense (L14 x L15)	$2,303			
17	Total non-payroll bill-related O&M expenses plus related non-payroll A&G expense (L11 + L16)	$37,084			
18	Per books NC retail 2018 bills	17,184,948	3/		
19	Cost per bill ($) (L17 x 1,000 / L18)	$2.15793			

1/ NCUC Form E-1, Item No. 45A, SWPA, Lines 198 and 221.
2/ NCUC Form E-1, Item No. 45A, SWPA, Lines 240 and 246.
3/ Based on information provided by Company.
4/ NC Retail Allocation Factor: SWPA - LAB (labor).
5/ NCUC Form E-1, Item No. 45A, SWPA, Account 904 - Uncollectible Accounts, Line 238, NC Retail amount.
6/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b)(3), Line 4.
7/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b)(3), Line 6.
8/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b)(3), Line 20.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO PAYMENT CARD FEES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(c)

Line No.	Item	Amount	
1	Annualized 2018 residential payment card transactions	3,060,671	1/
2	Annualized residential payment card transactions through supplemental update period	3,538,318	2/
3	Increase in annualized residential payment card transactions (L2 - L1)	477,647	
4	Transaction fees included in COS for non-payment card transactions	0.1990	3/
5	Remove O&M transaction costs included in COS (-L3 x L4 /1000)	($95)	

1/ Per Company response to PSDR 31-1.
2/ NCUC Form E-1, Item No. 10, NC-2503(E), Line 18
3/ Based on information provided by Company.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO FLOWBACK PROTECTED EDIT DUE TO TAX CUTS AND JOBS ACT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplementa
Schedule 3-1(d)

Line No.	Item	Amount	
	Income Statement Impact		
1	Annual amortization of protected EDIT - NC retail	($30,548)	1/
2	Income tax impact	7,078	2/
3	Annual amortization of protected EDIT - NC retail, net of tax (L1 + L2)	($23,470)	
	Rate Base Impact		
4	Adjustment to regulatory assets and liabilities (-L3)	$30,548	
5	Composite income tax rate	23.1693%	3/
6	Impact to accumulated deferred income taxes (-L4 x L5)	(7,078)	
7	Adjustment to rate base (L4 + L6)	$23,470	

1/ Smith Supplemental Exhibit 4, Column (a), Line 11.
2/ Line 1 times negative composite tax rate on Line 5.
3/ Dorgan Supplemental Exhibit 1, Schedule 1-3, Line 8.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT FOR CHANGE IN DEPRECIATION RATES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(e)

Line No.	Item	Total System		NC Retail Percentage		NC Retail Amount	
		(a)	1/	(b)	2/	(c)	
	Change in depreciation and amortization per Public Staff						
1	Production	$76,506		60.8591%	2/	$46,561	6/
2	Transmission	8,514		58.8448%	3/	5,010	6/
3	Distribution	(12,537)		87.1486%	4/	(10,926)	6/
4	Distribution COR adjustment - directly assigned	-		100.0000%		-	6/
5	General	(4,765)		73.7686%	5/	(3,515)	6/
6	General Plant Amortization	9,544		73.7686%	5/	7,041	6/
7	Adjust to deprec. and amort. for costs recovered in riders	1,362		60.8591%	2/	829	6/
8	Public Staff adjustment to depreciation and amortization expense	$78,625				45,000	
9	Company Adjustment					87,779	7/
10	Adjustment to depreciation and amortization expense (L8 - L9)					($42,779)	
11	Adjustment to accumulated depreciation (-L10)					$42,779	

1/ Based on recommendation of Public Staff witness McCullar.
2/ NCUC Form E-1, Item No. 45B, NC Retail Allocation Factor - DPALL, adjusted to SWPA.
3/ NCUC Form E-1, Item No. 45B, NC Retail Allocation Factor - DTALL, adjusted to SWPA.
4/ NCUC Form E-1, Item No. 45B, NC Retail Allocation Factor - RB PLT O DI, adjusted to SWPA.
5/ NCUC Form E-1, Item No. 45B, NC Retail Allocation Factor - NC Retail Allocation Factor - RB PLT O GN, adjusted to SWPA.
6/ Column (a) multiplied by Column (b).
7/ NCUC Form E-1, Item No. 10, NC-2601(D), Line 12, Total NC Retail Column, as adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO SALARIES AND WAGES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(f)

Line No.	Item	Duke Energy Carolinas	Duke Energy Progress	Service Company (DEBS)	Total
		(a)	(b)	(c)	(d)
1	Total labor cost per payroll company	$801,709 1/	$435,428 1/	$745,091 1/	
2	Allocation percentages	10.21% 1/	91.79% 1/	17.30% 1/	
3	Annualized salaries per Public Staff (L1 x L2)	81,894	399,697	128,906	
4	Per books salaries, 2018 test year	85,883 2/	425,470 2/	133,040 2/	
5	Public Staff adjustment to salaries and wages for employees	(3,989)	(25,773)	(4,134)	($33,897) 4/
6	Company Adjustment	(3,990) 3/	(25,774) 3/	(4,134) 3/	(33,897) 4/
7	Adjustment to salaries and wages (L5 - L6)	$0	$0	$0	0
8	Public Staff adjustment to total salaries and wages (L7)				$0
9	Percent charged to electric expense				75.98% 5/
10	Adjustment to net electric O&M salaries and wages (L8 x L9)				$0
11	Adjustment to net electric O&M salaries and wages (L10)				$0
12	Fringe benefits contribution rate				20.50% 6/
13	Adjustment to fringe benefits (L11 x L12)				$0
14	Total adjustment to O&M expense - total system (L10 + L13)				$0
15	NC Retail Allocation Factor				65.8950% 7/
16	Total adjustment to O&M expense - NC retail (L14 x L15)				$0
17	Impact on payroll taxes before Medicare				$0 8/
18	Impact on Medicare payroll taxes				0 9/
19	Adjustment to payroll taxes - total system (L17 + L18)				$0
20	NC Retail Allocation Factor				65.8950% 7/
21	Adjustment to payroll taxes - NC retail (L19 x L20)				$0

1/ NCUC E-1, Item No. 10, NC-1304(E), Lines 2 through 12.
2/ NCUC E-1, Item No. 10, NC-1301(E), Lines 3 through 5, Labor per Books Column.
3/ NCUC E-1, Item No. 10, NC-1301(E), Lines 3 through 5, Pro Forma HR Salaries Column.
4/ Sum of Columns (a) through (c).
5/ NCUC E-1, Item No. 10, NC-1301(E), Line 16.
6/ NCUC E-1, Item No. 10, NC-1301(E), Line 34.
7/ NC Retail Allocation Factor: SWPA - LAB (labor).
8/ Line 10 multiplied by 86.49% subject to OASDI (NCUC E-1, Item No. 10, NC-1301(E), Line 21) multiplied by 6.2% OASDI tax rate.
9/ Line 10 multiplied by 1.45% Medicare tax rate.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO INCENTIVES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(g)

Line No.	Item	Amount	
	Short Term Incentive Plan (STIP)		
1	Total Company STIP pay accrued expense associated with earnings per share (EPS)	$88,522	1/
2	Total Company STIP accrual	341,536	1/
3	Percentage of STIP related to EPS	25.92%	
4	STIP at target level associated with O&M expense per Company	69,054	2/
5	Adjustment to remove STIP related to EPS outcomes - total system (L3 x -L4)	(17,899)	
6	NC Retail Allocation Factor	65.8950%	3/
7	Adjustment to remove STIP related to EPS outcomes - NC retail (L5 x L6)	(11,795)	
8	Executive STIP already removed in executive compensation adjustment	87	4/
9	Adjustment to STIP (L7 + L8)	($11,708)	
	Long Term Incentive Plan (LTIP)		
10	Performance shares for EPS at target	$7,249	5/
11	Percentage associated with EPS and TSR	75.00%	
12	Adjustment to remove LTIP associated with EPS and TSR - total system (-L10 x L11)	(5,437)	
13	NC Retail Allocation Factor	65.8950%	3/
14	Adjustment to remove LTIP associated with EPS and TSR - NC retail (L12 x L13)	(3,583)	
15	Executive LTIP already removed in executive compensation adjustment	639	4/
16	Adjustment to LTIP (L14 + L15)	($2,944)	
17	Total adjustment to incentive pay (L9 + L16)	($14,652)	

1/ Company Response to Public Staff Data Request No. 32, Item 10.
2/ NCUC Form E-1, Item No. 10, NC-1310(E), Line 6.
3/ NC Retail Allocation Factor: SWPA - LAB (labor).
4/ Based on executive compensation adjustment.
5/ NCUC Form E-1, Item 10, NC-1310-3(E), Page 1, Line 13, Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO SEVERANCE COSTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(h)

Line No.	Item	Amount	
	Income Statement Impact		
1	Remove actual severance costs in 2018	($52,890)	1/
2	Annual amortization related to severance costs based on 5 year amortization	9,859	2/
3	Total Carolinas adjustment to remove actual severance costs (L1 + L2)	(43,031)	
4	NC Retail Allocation Factor	65.8950%	3/
5	NC Retail adjustment to remove severance costs (L3 x L4)	(28,355)	
6	Company adjustment	(24,025)	4/
7	Public Staff adjustment to O&M related to severance costs (L5 - L6)	($4,331)	
	Rate Base Impact		
8	Impact to working capital investment per Company	$21,655	5/
9	Impact to working capital investment per Public Staff	0	6/
10	Adjustment to working capital investment (L9 - L8)	($21,655)	
11	Impact to ADIT per Company	($5,017)	7/
12	Impact to ADIT per Public Staff	0	6/
13	Adjustment to ADIT (L12 - L11)	$5,017	

1/ NCUC Form E-1, Item No. 10, NC-2001(E), Line 2, Total System Column.
2/ NCUC Form E-1, Item No. 10, NC-2001(E), Line 3, Total System Column.
3/ NC Retail Allocation Factor: SWPA - LAB (labor).
4/ NCUC E-1, Item No. 10, NC-2001(E), Line 4, NC Retail Column.
5/ NCUC E-1, Item No. 10, NC-2001(E), Line 14, NC Retail Column.
6/ Public Staff recommendation.
7/ NCUC E-1, Item No. 10, NC-2001(E), Line 17, NC Retail Column.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO EXECUTIVE COMPENSATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(i)

Line No.	Item	Amount	
1	Executive compensation for top 5 executives per Company	$7,246	1/
2	Inclusion of executive benefits in adjustment	486	2/
3	Executive compensation subject to exclusion adjustment per Public Staff (L1 + L2)	$7,732	
4	NC Retail Allocation Factor	65.8950%	3/
5	NC retail portion of executive compensation subject exclusion adjustment (L3 x L4)	$5,095	
6	Exclusion percentage	50.00%	4/
7	Public Staff adjustment to exclude executive compensation (L6 x L7)	($2,548)	
8	Company adjustment	(2,387)	5/
9	Adjustment to remove additional executive compensation (L7 - L8)	($160)	

1/ NCUC Form E-1, Item No. 10, NC-0701, Line 3.
2/ Based on Company response to PSDR-41, Item 2.
3/ NC Retail Allocation Factor: SWPA - LAB (labor).
4/ NCUC Form E-1, Item No. 10, NC-0701, Line 10.
5/ NCUC Form E-1, Item No. 10, NC-0701, Line 11, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO AVIATION EXPENSES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(j)

Line No.	Item	Amount	
	Wages, benefits, materials, etc.		
1	Corporate aviation O&M and depreciation expense	$4,386	1/
2	Percentage to be excluded per Public Staff	56.95%	2/
3	Corporate aviation expenses to be excluded per Public Staff (L1 x L2)	$2,498	
4	Specific charter flights to be excluded	-	
5	Total corporate aviation expenses to be excluded per Public Staff (L3 + L4)	$2,498	
6	Company adjustment	2,193	3/
7	Additional aviation O&M expenses to be excluded (L5 - L6)	$305	
8	NC Retail Allocation Factor	65.8950%	4/
9	Public Staff adjustment to aviation O&M expenses (-L7 x L8)	($201)	
	General taxes		
10	Corporate aviation general taxes	$53	5/
11	Percentage to be excluded per Public Staff	56.95%	2/
12	Corporate aviation general taxes to be excluded per Public Staff (L10 x L11)	$30	
13	Company adjustment	27	6/
14	Additional aviation general taxes to be excluded (L12 - L13)	$3	
15	NC Retail Allocation Factor	65.8950%	4/
16	Public Staff adjustment to aviation general taxes (-L14 x L15)	($2)	
	Commercial flights		
17	International flight expense	$1,325	7/
18	Allocation percentage from DEBS to DEP	23.35%	8/
19	International flight expense allocated to DEP (L17 x L18)	$309	
20	NC Retail Allocation Factor	65.8950%	4/
21	Public Staff adjustment to O&M for commercial flights (-L19 x L20)	($204)	

1/ NCUC Form E-1, Item No. 10, NC-1702, Line 19.
2/ Calculated by Public Staff based on Company response to Public Staff Data Requests.
3/ NCUC Form E-1, Item No. 10, NC-1702, Line 22.
4/ NC Retail Allocation Factor: SWPA - LAB (labor).
5/ NCUC Form E-1, Item No. 10, NC-1702, Line 1, Total Duke Energy Progress Column.
6/ NCUC Form E-1, Item No. 10, NC-1702, Line 3, Total Duke Energy Progress Column.
7/ Calculated by Public Staff based on Company response to Public Staff Data Requests.
8/ Based on Company response to PSDR-28, Item 7(b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO OUTSIDE SERVICES
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(k)

Line No.	Item	Amount	
1	Remove items related to coal ash litigation	$179	1/
2	Remove items identified that Company has agreed to remove	19	1/
3	Remove additional items identified by Public Staff that should be removed	42	1/
4	Total Public Staff adjustment to outside services (L1 + L2 + L3)	$239	
5	NC Retail Allocation Factor	60.8591%	2/
6	Public Staff adjustment to outside services - NC retail (-L4 x L5)	($146)	

1/ Based on information provided by Company in response to PSDR-75, Items 1 and 2, and advice of legal counsel.

2/ NC Retail Allocation Factor: SWPA - DP (production demand).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO NORMALIZE STORM COSTS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(l)

Line No.	Item	Amount	
	Normalized storm expense		
1	NC retail amount of storm costs considered normal for 2018	$25,078	1/
2	NC Retail Allocation Factor	83.9171%	2/
3	2018 storm costs to be included in calculation of normalized level (L1 / L2)	29,884	
4	2010 through 2019 costs adjusted for inflation, excluding 2018	114,099	3/
5	Total storm costs for ten years adjusted for inflation (L3 + L4)	143,983	
6	Number of years	10	
7	Normalized level of storm costs - total system (L5 x L6)	14,398	
8	NC Retail Allocation Factor	83.9171%	2/
9	Normalized level of storm costs per Public Staff (L7 x L8)	12,082	
10	2018 Storm costs	2,782	4/
11	Total Public Staff adjustment to storm expense (L11 + L12)	9,300	

1/ NCUC Form E-1, Item No. 10, NC-2905(E), Line 2, NC Retail column
2/ NC Retail Allocation Factor: SWPA - RB_PLT_O_DI_OH_LN (distribution plant, overhead lines).
3/ Per Company response to PSDR 27-1, and storm costs included in Sub 1142.
4/ Per Company response to PSDR 27-1.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO STORM DEFERRAL
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(m)

Line No.	Item	Amount	
	Income Statement Impact		
1	Impact to depreciation and amortization for storm deferral per Company	$43,157	1/
2	Impact to depreciation and amortization to remove storm assets from rate base	(1,636)	2/
3	Impact to depreciation and amortization for storm deferral per Public Staff	-	3/
4	Adjustment to deprecation and amortization for storm deferral (L1 + L2 + L3)	(44,793)	
	Rate Base Impact		
5	Projected storm deferral balance per Company	$604,202	4/
6	Projected storm deferral balance per Public Staff	-	3/
7	Adjustment to working capital for storm deferral (L6 - L5)	($604,202)	
8	Impact to ADIT for storm deferral per Company	($139,989)	5/
9	Impact to ADIT for storm deferral per Public Staff	-	3/
10	Adjustment to ADIT for storm deferral (L9 - L8)	$139,989	
11	Adjustment to remove storm assets from rate base	($18,133)	2/
12	Adjustment to remove accumulated depreciation for storm assets from rate base	1,812	2/
13	Adjustment to rate base to remove storm assets (L11 + L12)	($16,321)	

1/ NCUC Form E-1, Item No. 10, NC-2901(E), Line 4, as adjusted to SWPA.
2/ Provided by Company.
3/ Public Staff recommendation to remove storm deferral for securitization.
4/ NCUC Form E-1, Item No. 10, NC-2901(E), Line 16, as adjusted to SWPA.
5/ NCUC Form E-1, Item No. 10, NC-2901(E), Line 19, as adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO CHARITABLE CONTRIBUTIONS, CORPORATE SPONSORSHIPS, AND CORPORATE DONATIONS
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(n)

Line No.	Item	Amount	
1	Remove charitable contributions not sought for recovery	$13	1/
2	Remove corporate sponsorships not sought for recovery and miscellaneous dues	37	2/
3	Removal of corporate donations and membership dues related to unregulated products	9	3/
4	Total sponsorships and donations to be removed per Public Staff (L1 + L2 + L3)	$59	
5	NC Retail Allocation Factor	60.8591%	4/
6	Public Staff adjustment to remove charitable contributions and corporate sponsorships & donations - NC retail (-L4 x L5)	($36)	

1/ Company Response to PSDR 34-4.
2/ Company Response to PSDR 34-3.
3/ Company Response to PSDR 34-6.
4/ NC Retail Allocation Factor: SWPA - DP (production demand).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO LOBBYING EXPENSE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(o)

Line No.	Item	Amount	
1	Remove Stakeholder Engagement O&M charges related to lobbying	$1,343	1/
2	Remove State Government Affairs O&M charges related to lobbying	94	1/
3	Remove Federal Affairs O&M charges related to lobbying	992	2/
4	Remove Edison Electric Institute (EEI) O&M charges related to lobbying	99	1/
5	Total lobbying costs to be removed from O&M expense (L1 + L2 + L3 + L4)	$2,528	
6	NC Retail Allocation Factor	60.8591%	3/
7	Public Staff adjustment to remove lobbying costs (-L5 x L6)	($1,538)	

1/ Based upon Company response to PSDR-35, Item 2(g).
2/ Based on Company response to PSDR-35, Item 5, and NCUC Form E-1, Item 16(b).
3/ NC Retail Allocation Factor: SWPA - DP (production demand).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO BOARD OF DIRECTORS EXPENSE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(p)

Line No.	Item	Amount	
1	Total Board of Directors (BOD) cash compensation	$421	1/
2	Percentage of exclusion per Public Staff	50%	2/
3	Public Staff adjustment to BOD compensation (-L1 x L2)	($210)	
4	Board of Directors (BOD) expenses	$155	
5	Percentage of exclusion per Public Staff	50%	
6	Public Staff adjustment to BOD expenses (-L4 x L5)	($78)	
7	BOD insurance charged to DEP	3,514	3/
8	Percentage of exclusion per Public Staff	50%	2/
9	Public Staff adjustment to BOD insurance (-L7 x L8)	($1,757)	
10	BOD and executive members expenses allocated to DEP	81	4/
11	Percentage of exclusion per Public Staff	50%	2/
12	Public Staff adjustment to BOD and executive members expenses (-L10 x L11)	($41)	
13	Total Public Staff adjustment to BOD compensation and expenses (L3 + L6 + L9 + L12)	($2,086)	
14	NC Retail Allocation Factor	60.8591%	5/
15	Public Staff adjustment to BOD expenses - NC retail (L13 x L14)	($1,270)	

1/ Amount from 2018 Proxy Statement, allocated to DEP.
2/ Recommended by Public Staff.
3/ Company Response to PSDR-40, Items 2 and 4.
4/ Company Response to PSDR-40, Item 1(a).
5/ NC Retail Allocation Factor: SWPA - DP (production demand).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO END OF LIFE RESERVE FOR NUCLEAR MATERIALS AND SUPPLIES AMORTIZATION EXPENSE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(q)

Line No.	Item	Brunswick 1 (a)		Brunswick 2 (b)		Harris (c)		Robinson (d)		Total (e)	
1	Inventory as of December 31, 2018	$97,698	1/	$97,698	1/	$126,342	1/	$75,117	1/	$396,855	7/
2	Adjustment to remove inventory	(2,335)	2/	(2,320)	2/	(2,400)	2/	(1,845)	2/	(8,900)	8/
3	Inventory balance per Public Staff (L1 + L2)	95,363		95,378		123,942		73,272		$387,955	
4	Percentage of M&S with salvage value or transferrable	10%	8/	10%	8/	10%	8/	10%	8/		
5	Nuclear M&S inventory base for amortization per Public Staff (L3 x (1-L4))	85,827		85,840		111,548		65,945			
6	NC Retail Allocation Factor	60.859%	3/	60.859%	3/	60.859%	3/	60.859%	3/		
7	NC retail nuclear M&S base for amortization (L5 x L6)	52,234		52,241		67,887		40,134			
8	Less: Projected inventory reserve at 8/31/2020	11,309	4/	12,278	4/	9,071	4/	13,703	4/		
9	NC nuclear reserve required at rates effective date (L7 - L8)	40,925		39,963		58,816		26,431			
10	Years of remaining plant life	16.00	5/	14.00	5/	26.00	5/	10.00	5/		
11	NC retail annual expense for reserve per Public Staff (L9 / L10)	2,558		2,855		2,262		2,643		$10,318	8/
12	Amount required per Company	3,006	6/	3,295	6/	2,594	6/	3,230	6/	12,125	8/
13	Public Staff adjustment to nuclear M&S reserve amortization expense (L11 - L12)	($448)		($440)		($332)		($587)		($1,807)	

1/ NCUC Form E-1, Item 10, NC-2803, Line 2, adjusted to SWPA.
2/ Total adjustment from Column (e) allocated based on inventory amounts from Line 1.
3/ NC Retail Allocation Factor: SWPA - DP (production demand).
4/ NCUC Form E-1, Item 10, NC-2803, Line 16, adjusted to SWPA.
5/ NCUC Form E-1, Item 10, NC-2803, Line 22, adjusted to SWPA.
6/ NCUC Form E-1, Item 10, NC-2803, Line 24, adjusted to SWPA.
7/ Sum of Columns (a) through (d).
8/ Based on recommendation of Public Staff witness Metz.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO RATE CASE EXPENSE AND AMORTIZATION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(r)

Line No.	Item	Amount	
	Income Statement Impact		
1	Actual rate case expense incurred through February 29, 2020	$2,539	1/
2	Amortization period in years	5	2/
3	Annual normalized level of rate case expense per Public Staff (L1 / L2)	$508	
4	Annual normalized level of rate case expense per Company	701	3/
5	Adjustment to annual normalized rate case expense (L3 - L4)	($193)	
	Rate Base Impact		
6	Projected working capital after first year of amortization per Company	$2,670	4/
7	Public Staff recommended regulatory asset amount for rate case expense	0	
8	Adjustment to rate base for rate case expense (L6 - L7)	($2,670)	
9	Impact to ADIT for storm deferral per Company	($619)	
10	Impact to ADIT for storm deferral per Public Staff	0	
11	Adjustment to ADIT for storm deferral (L10 - L9)	$619	

1/ NCUC Form E-1, Item No. 10, NC-1602(E), Line 28.
2/ NCUC Form E-1, Item No. 10, NC-1601(E), Line 5.
3/ NCUC Form E-1, Item No. 10, NC-1601(E), Line 6.
4/ NCUC Form E-1, Item No. 10, NC-1601(E), Line 18.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
NET OPERATING INCOME, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(s)

Line No.	Item	SWPA Company NOI Reallocated By Public Staff 1/	Summer CP Company NOI - Company Allocations 2/	Cost of Service Study Adjustments 3/
		North Carolina Retail Operations		
		(a)	(b)	(c)
1	Electric operating revenue	$3,360,843	$3,361,009	($166)
	Electric operating expenses:			
	Operation and maintenance:			
2	Fuel used in electric generation	$851,667	$851,667	$0
3	Purchased power	156,088	156,798	(710)
4	Other operation and maintenance expense	865,678	863,429	2,249
5	Depreciation and amortization	943,851	950,060	(6,209)
6	General taxes	101,816	102,506	(690)
7	Interest on customer deposits	7,971	7,971	-
8	Net income taxes	48,639	47,541	1,098
9	Amortization of investment tax credit	(3,580)	(3,614)	34
10	Total electric operating expenses (Sum of L2 through L9)	$2,972,130	$2,976,358	($4,228)
11	Operating income (L1 - L10)	$388,714	$384,651	$4,062

1/ Dorgan Supplemental Exhibit III, Schedule 2, Column (c).
2/ Dorgan Supplemental Exhibit I, Schedule 3, Column (a).
3/ Column (a) - Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO ASHEVILLE COMBINED CYCLE PRO FORMA O&M EXPENSE AND REGULATORY ASSET
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Exhibit 1
Schedule 3-1(t)

Line No.	Item	NC Retail Amount	
	Income Statement Impact		
1	Average Annual Asheville Combined Cycle O&M - NC Retail per Company	$6,087	1/
2	Average Annual Asheville Combined Cycle O&M - NC Retail Per Public Staff	$2,604	2/
3	Adjustment to Asheville CC O&M expense (L2 - L1)	($3,483)	
	Rate Base Impact		
4	Asheville CC Inventory per Company	$3,461	3/
5	Asheville CC inventory per Public Staff	3,461	2/
6	Adjustment to Asheville Inventory (L5 - L4)	$0	
7	Regulatory Asset for Asheville CCs as of Sep 1, 2020 per Company	$22,886	4/
8	Regulatory Asset for Asheville CCs as of Sep 1, 2020 per Public Staff	0	5/
9	Adjustment to Asheville CC Regulatory Asset (L7 - L8)	($22,886)	
10	Accumulated deferred income taxes related to the regulatory asset per Company	($5,303)	6/
11	Accumulated deferred income taxes related to the regulatory asset per Public Staff	0	5/
12	Adjustment to accumulated deferred income taxes	$5,303	
13	Adjustment to rate base for regulatory asset for Asheville CC (L6 + L9 + L12)	($17,583)	

1/ NCUC Form E-1, Item No. 10, NC-3401(E), Line 2, adjusted to SWPA.
2/ Per Public Staff witness Dustin Metz, adjusted to SWPA for the Asheville CC.
3/ NCUC Form E-1, Item No. 10, NC-3401(E), Line 16, adjusted to SWPA.
4/ NCUC Form E-1, Item No. 10, NC-3401(E), Line 21, adjusted to SWPA.
5/ Public Staff removed the regulatory asset since the annuity method was used for determining the amortization.
6/ NCUC Form E-1, Item No. 10, NC-3401(E), Line 24, adjusted to SWPA.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO ASHEVILLE COMBINED CYCLE DEFERRAL
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1 (t)(1)

Line No.	Item	Amount	
	Annuity Factor		
1	Amortization period recommended by Public Staff in years	5	1/
2	Payment per period	1	
3	After tax rate of return (L18)	6.0790%	
4	Present value of 1 dollar over number of years with 1 payment per year	4.2033	
5	1 plus (interest rate divided by two)	1.0304	
6	Annuity factor (L4 x L5)	4.3311	
7	Deferred costs per Public Staff	$35,544	2/
8	Annuity factor per Public Staff (L6)	4.3311	
9	Annual levelized amortization expense per Public Staff (L7 / L8)	$8,207	
10	Annual amortization expense per Company	11,037	3/
11	Adjustment to Asheville CC deferral amortization expense (L9 - L10)	($2,830)	

		Capital Structure (a)	Cost Rates (b)	Overall Rate of Return 8/ (c)	Net of Tax Rate (d)
	After Tax Rate of Return				
12	Long-term debt	50.00% 4/	4.110% 6/	2.055%	1.579% 9/
13	Common equity	50.00% 5/	9.000% 7/	4.500%	4.500% 10/
14	Total	100.00%		6.555%	6.079%

1/ Rider period recommended by Public Staff.
2/ Dorgan Supplemental Exhibit 1, Schedule 3-1(t)(2), Column (j), Line 22 plus Dorgan Supplemental Exhibit 1, Schedule 3-1(t)(3), Column (j), Line 22.
3/ NCUC Form E-1, Item No. 10, NC-3401(E), Line 7 adjusted to SWPA.
4/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 1, Column (a).
5/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 2, Column (a).
6/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 1, Column (g).
7/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 2, Column (g).
8/ Column (a) multiplied by Column (b).
9/ Column (c) multiplied by (1 minus combined income tax rate of 23.1693%).
10/ Amount from Column (c).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF DEFERRED COSTS FOR ASHEVILLE COMBINED CYCLE - PRODUCTION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(t)(2)

Line No.	Item		December 2019	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	Totals 8/
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Production Plant placed into service - NC Retail	1/	302,260	351,195	467,718	467,718	$467,718	$467,718	$467,718	$467,718	$467,718	$467,718
2	ADIT balance	1/	(28,013)	(32,548)	(43,347)	(43,347)	(43,347)	(43,347)	(43,347)	(43,347)	(43,347)	(43,347)
3	Average inventory balance	1/	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735	3,735
4	Accumulated Depreciation	1/	0	(1,035)	(2,238)	(3,840)	(5,442)	(7,044)	(8,646)	(10,248)	(11,850)	(11,850)
5	Remove CWIP in Rate Base	1/	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)	(102,930)
6	Rate base balance for return (L3 + L4 + L5)		175,053	218,417	322,939	321,337	319,735	318,133	316,531	314,929	313,327	313,327
7	Pre-tax cost of capital rate	2/	8.6444%	8.6444%	8.6444%	8.6444%	8.6444%	8.6444%	8.6444%	8.6444%	8.6444%	
8	Deferred monthly cost of capital (L6 x L7/12)	3/	163	1,573	2,326	2,315	2,303	2,292	2,280	2,269	2,257	17,778
9	Plant balance (L3)		$0	302,260	351,195	467,718	467,718	467,718	467,718	467,718	467,718	
10	Annual depreciation rate	4/	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%	4.11%	
11	Deferred monthly depreciation expense (L9 x L10/12)		0	1,035	1,203	1,602	1,602	1,602	1,602	1,602	1,602	11,850
12	Deferred O&M expense	5/	28	218	218	218	218	218	218	218	218	1,770
13	Plant balance (L3)		$302,260	$351,195	$467,718	$467,718	$467,718	$467,718	$467,718	$467,718	$467,718	
14	Annual Property tax rate	6/	0.3626%	0.3626%	0.3626%	0.3626%	0.3626%	0.3626%	0.3626%	0.3626%	0.3626%	
15	Deferred monthly property tax expense (L13 x L14/12)		12	106	141	141	141	141	141	141	141	1,105
16	Cumulative deferred costs (L8 + L11+L12+L15)		203	3,135	7,023	11,298	15,562	19,815	24,056	28,285	32,503	
17	Composite income tax rate	7/	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	
18	Income tax on deferred expenses (-L16 x L17)		(47)	(726)	(1,627)	(2,618)	(3,606)	(4,591)	(5,574)	(6,554)	(7,531)	
19	Deferred costs, net of tax (L16 + L18)		156	2,409	5,396	8,680	11,956	15,224	18,482	21,731	24,972	
20	Pre-tax cost of capital rate (L7)	2/	8.644%	8.644%	8.644%	8.644%	8.644%	8.644%	8.644%	8.644%	8.644%	
21	Pre-tax return on monthly deferred expenses (L19 x L20)		1	17	39	63	86	110	133	157	180	785
22	Total deferred costs per Public Staff (L8 + L11 + L12 + L15 + L21)		$204	$2,949	$3,927	$4,338	$4,350	$4,362	$4,374	$4,386	$4,398	$33,288

1/ NCUC Form E-1, Item No. 10, NC-3403, updated to December31, 2019, Columns (d) through (n).
2/ Pre-tax costs of capital per Order Granting General Rate Increase issued on February 23, 2018, in Docket No. E-2, Sub 1142.
3/ Monthly deferred cost of capital multiplied by 4 days, divided by 31 days.
4/ NCUC Form E-1, Item No. 10, NC-3403, Page 1 of 2, Column (p), Line 30.
5/ Per Public Staff witness Metz. First month multiplied by 4 days, divided by 31 days.
6/ NCUC Form E-1, Item No. 10, NC-3403, Page 1 of 2, Column (p), Line 31.
7/ Dorgan Supplemental Exhibit 1, Schedule 1-3, Line 8, Column (a).
8/ Sum of Columns (a) through (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF DEFERRED COSTS FOR ASHEVILLE COMBINED CYCLE - TRANSMISSION
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(t)(3)

Line No.	Item		December 2019	January 2020	February 2020		March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	Total 8/
			(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Transmission Plant placed into service	1/	$7,422	$7,422	$7,422		7,422	7,422	7,422	7,422	7,422	7,422	7,422
2	ADIT balance	1/	(67)	(67)	(67)		(67)	(67)	(67)	(67)	(67)	(67)	(67)
3	Average inventory balance	1/	0	0	0		0	0	0	0	0	0	-
4	Accumulated Depreciation	1/	0	(12)	(24)		(36)	(48)	(60)	(72)	(84)	(96)	(96)
5	Remove CWIP in Rate Base	1/	0	0	0		0	0	0	0	0	0	-
6	Rate base balance for return (L3 + L4 + L5)		7,355	7,343	7,331		7,319	7,307	7,295	7,283	7,271	7,259	$7,259
7	Monthly pre-tax cost of capital rate	2/	8.6444%	8.6444%	8.6444%	4/	8.6444%	8.6444%	8.6444%	8.6444%	8.6444%	8.6444%	
8	Deferred monthly cost of capital (L6 x L7/12)	3/	53	53	53		53	53	53	53	52	52	474
9	Plant balance (L3)		$0	7,422	7,422		7,422	7,422	7,422	7,422	7,422	7,422	
10	Annual depreciation rate	4/	1.90%	1.90%	1.90%	5/	1.90%	1.90%	1.90%	1.90%	1.90%	1.90%	
11	Deferred monthly depreciation expense (L9 x L10/12)		0	12	12		12	12	12	12	12	12	96
12	Deferred O&M expense	5/	0	0	0	6/	0	0	0	0	0	0	0
13	Plant balance (L3)		$7,422	$7,422	$7,422		$7,422	$7,422	$7,422	$7,422	$7,422	$7,422	
14	Annual Property tax rate	6/	0.3626%	0.3626%	0.3626%	7/	0.3626%	0.3626%	0.3626%	0.3626%	0.3626%	0.3626%	
15	Deferred monthly property tax expense (L13 x L14/12)		2	2	2		2	2	2	2	2	2	18
16	Cumulative deferred costs (L8 + L11+L12+L15)		55	122	189	8/	256	322	389	455	522	588	2,898
17	Composite income tax rate	7/	23.1693%	23.1693%	23.1693%	9/	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	23.1693%	
18	Income tax on deferred expenses (-L16 x L17)			(28)	(44)		(59)	(75)	(90)	(105)	(121)	(136)	(658)
19	Deferred costs, net of tax (L16 + L18)		55	94	145		197	247	299	350	401	452	
20	Pre-tax cost of capital rate (L7)	2/	8.644%	8.644%	8.644%		8.644%	8.644%	8.644%	8.644%	8.644%	8.644%	
21	Pre-tax return on monthly deferred expenses (L19 x L20)		0	1	1		1	2	2	3	3	3	16
22	Total deferred costs per Public Staff (L8 + L11 + L12 + L15 + L21)		$55	$95	$146		$198	$249	$301	$353	$404	$455	$2,256

1/ Smith Supplemental Exhibit 1 and NCUC Form E-1, Item No. 10, NC-3404, Supplemental (C), December Update, Page 1 of 2, Columns (d) through (n).
2/ Pre-tax costs of capital per Order Granting General Rate Increase issued on February 23, 2018, in Docket No. E-2, Sub 1142.
3/ Monthly deferred cost of capital times 4 days, divided by 31 days.
4/ Smith Supplemental Exhibit 1 and NCUC Form E-1, Item No. 10, NC-3404, Page 1 of 2, Column (p), Line 30.
5/ Per Public Staff witness Metz. First month multiplied by 4 days, divided by 31 days.
6/ Smith Supplemental Exhibit 1 and NCUC Form E-1, Item No. 10, NC-3404, Page 1 of 2, Column (p), Line 31.
7/ Dorgan Supplemental Exhibit 1, Schedule 1-3, Line 8, Column (a).
8/ Sum of Columns (a) through (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
NON-FUEL O&M DISPLACEMENT ADJUSTMENT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(u)

Line No.	Item	Amount	
1	Asheville Coal Plant generation MW Retired per Company	400	1/
2	Capacity Factor	36%	2/
3	Hours per year	8,760	
4	Total mWh for Asheville Coal generation (L1 x L2 x L3)	1,261,440	
5	Asheville CC generation mWh	580	3/
6	Capacity Factor	70%	4/
7	Hours per year	8,760	
8	Total mWh for Asheville CC generation at (L5 x L6 x L7)	3,556,560	
9	Additional mWh generation added - system (L8 - L4)	2,295,120	
10	NC retail allocation percentage	60.2976%	5/
11	NC retail additional mWh generation added	1,383,902	
12	Non-fuel energy-related expense factor used by Public Staff	0.00582786	6/
13	NC retail displacement adjustment (L11 x -L12)	$ (8,065)	

1/ Based on DEP Application.
2/ 2018 test year capacity factor provided by Public Staff witness Metz.
3/ Based on Asheville CC MW closed to plant.
4/ Based on discussions with Public Staff witness Metz.
5/ NC retail allocation factor: SWPA_RB_PLT_O_PR
6/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b)(3), Line 24, divided by 1,000

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
ADJUSTMENT TO COMPANY'S INFLATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(v)

Line No.	Item	Amount	
1	Total non-labor O&M expense to be adjusted per Company	$212,332	1/
2	Public Staff adjustment to variable O&M expenses for changes in customer growth	(5,440)	2/
3	Public Staff adjustment to aviation expense - Salary & Wage component	(201)	3/
4	Public Staff adjustment to outside services	(146)	4/
5	Public Staff adjustment to sponsorships and donations	(36)	5/
6	Public Staff adjustment to lobbying	(1,538)	6/
7	Public Staff adjustment to Board of Directors expenses	(1,270)	7/
8	Total adjusted O&M subject to inflation (Sum of L1 through L7)	$203,701	
9	Inflation percentage based on January 31, 2020 update	2.03%	8/
10	Public Staff inflation adjustment (L7 x L8)	$4,135	
11	Company adjustment	1,336	9/
12	Public Staff adjustment to inflation (L9 - L10)	$2,799	

1/ NCUC Form E-1, Item No. 10, NC-1201(E), Line 27, NC Retail Column.
2/ Dorgan Supplemental Exhibit 1, Schedule 3-1(b)(1), Line 14.
3/ Dorgan Supplemental Exhibit 1, Schedule 3-1(j), Line 9.
4/ Dorgan Supplemental Exhibit 1, Schedule 3-1(k), Line 6.
5/ Dorgan Supplemental Exhibit 1, Schedule 3-1(n), Line 6.
6/ Dorgan Supplemental Exhibit 1, Schedule 3-1(o), Line 7.
7/ Dorgan Supplemental Exhibit 1, Schedule 3-1(p), Line 15.
8/ Dorgan Supplemental Exhibit 1, Schedule 3-1(v)(1), Line 4, Column (e).
9/ NCUC Form E-1, Item No. 10, NC-1201(E), Line 29, NC Retail Column.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF INFLATION RATE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(v)(1)

Line No.	Item	CPI (a)	PPI Finished Goods Less Food & Energy (b)	PPI Processed Materials Less Food & Energy (c)	PPI Average (d)	Inflation Rate (e)
1	February 2020	258.7 1/	209.1 1/	199.2 1/		
2	Thirteen month average for test year	250.8 2/	203.2 2/	201.4 2/		
3	Increase (decrease) from average to January 2020 (L1 - L2)	7.9	5.9	(2.2)		
4	Percentage increase (decrease)	3.14% 3/	2.90% 3/	-1.09% 3/	0.91% 4/	2.03% 5/

1/ NCUC Form E-1, Item No. 10, NC-1203(E), 1204(E), and 1205(E) January 2020.
2/ NCUC Form E-1, Item No. 10, NC-1202(E), Line 15.
3/ Line 3 divided by Line 2.
4/ Average of percentage increases (decreases) in Columns (b) and (c).
5/ Average of CPI percentage increase (decrease) and PPI average percentage increase (decrease) in Columns (a) and (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
INTEREST SYNCHRONIZATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(w)

Line No.	Item	Amount	
1	Public Staff original cost rate base	$10,440,896	1/
2	Public Staff long term debt ratio	50.000%	2/
3	Public Staff embedded cost of debt	4.110%	3/
4	Public Staff interest expense income tax deduction (L1 x L2 x L3)	$214,560	
5	Company interest expense income tax deduction	207,855	4/
6	Adjustment to interest expense (L4 - L5)	$6,705	
7	Composite tax rate	23.1693%	5/
8	Adjustment to income taxes (-L6 x L7)	($1,554)	

1/ Dorgan Supplemental Exhibit 1, Schedule 2, Line 16, Column (c).
2/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 1, Column (c).
4/ Dorgan Supplemental Exhibit 1, Schedule 3-1(w)(1), Line 4.
5/ Dorgan Supplemental Exhibit 1, Schedule 1-3, Line 8.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 3-1(w)(1)

CALCULATION OF COMPANY'S INTEREST SYNCHRONIZATION ADJUSTMENT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Line No.	Item	Amount	
1	NC retail rate base per Company	$10,644,806	1/
2	Long tern debt ratio per Company	47.000%	2/
3	Long term debt cost rate per Company	4.155%	3/
4	Interest tax deduction per Company (L1 x L2 x L3)	$207,855	

1/ Dorgan Supplemental Exhibit 1, Schedule 2, Line 16, Column (a).
2/ Smith Supplemental Exhibit 1, Page 2, Line 1, Column 2.
3/ Smith Supplemental Exhibit 1, Page 2, Line 1, Column 7.

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
RETURN ON EQUITY AND ORIGINAL COST RATE BASE BEFORE AND AFTER PUBLIC STAFF PROPOSED INCREASE
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 4

			Before Public Staff Proposed Increase				After Public Staff Proposed Increase			
Line No.	Item	Capitalization Ratio	NC Retail Rate Base	Embedded Cost or Return	Weighted Cost or Return	Net Operating Income	NC Retail Rate Base	Embedded Cost or Return	Weighted Cost or Return	Net Operating Income
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Long-term debt	50.000% 1/	$5,220,448 2/	4.11% 1/	2.06% 5/	$214,560 6/	$5,226,125 9/	4.11% 1/	2.0550% 11/	$214,794 12/
2	Common equity	50.000% 1/	5,220,448 2/	7.12% 4/	3.56% 5/	371,774 7/	5,226,125 9/	9.00% 1/	4.500% 11/	470,351 12/
3	Total (L1 + L2)	100.000%	$10,440,896 3/		5.62%	$586,334 8/	$10,452,251 10/		6.5550%	$685,145

1/ Per Public Staff witness Woolridge.
2/ Column (b), Line 3 multiplied by Column (a), Lines 1 and 2
3/ Dorgan Supplemental Exhibit 1, Schedule 2, Line 16, Column (c).
4/ Line 2, Column (e) divided by Line 2, Column (b).
5/ Column (a) multiplied by Column (c).
6/ Line 1, Column (b) multiplied by Line1, Column (c).
7/ Line 3, Column (e) minus Line 1, Column (e).
8/ Dorgan Supplemental Exhibit 1, Schedule 3, Line 17, Column (c).
9/ Line 3, Column (f) multiplied by Column (a), Lines 1 and 2
10/ Dorgan Supplemental Exhibit 1, Schedule 2, Line 16, Column (e).
11/ Column (a) multiplied by Column (g).
12/ Column (f) multiplied by Column (g).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF PUBLIC STAFF'S ADDITIONAL GROSS REVENUE REQUIREMENT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 1
Schedule 5

Line No.	Item	Debt		Equity		Total 7/
		(a)		(b)		(c)
	Calculation of additional gross revenue requirement					
1	Required net operating income	$214,794	1/	470,351	4/	$685,145
2	Net operating income before proposed increase	214,560	2/	371,774	5/	586,334
3	Additional net operating income requirement (L1 - L2)	$234		$98,577		$98,811
4	Retention factor	0.9963091	3/	0.7654709	6/	
5	Additional revenue requirement (L3 ÷ L4)	$235		$128,779		$129,014

1/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 1, Column (i).
2/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 1, Column (e).
3/ Dorgan Supplemental Exhibit 1, Schedule 1-2, Line 10.
4/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 2, Column (i).
5/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 2, Column (e).
6/ Dorgan Supplemental Exhibit 1, Schedule 1-2, Line 14.
7/ Column (a) plus Column (b).
8/ Smith Supplemental Exhibit 2 Page 1, Line 5.

INDEX TO DORGAN SUPPLEMENTAL EXHIBIT 2

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF LEVELIZED EDIT RIDER CREDIT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 2
Schedule 1

Line No.	Item	Year 1 Revenue Requirement		Year 2 Revenue Requirement		Year 3 Revenue Requirement		Year 4 Revenue Requirement		Year 5 Revenue Requirement		Total Revenue Requirement	
		(a)		(b)		(c)		(d)		(e)		(f)	
1	Total NC retail regulatory liability to be amortized	($403,750)	1/	($403,750)	1/	($403,750)	1/	($403,750)	1/	($403,750)	1/		
2	Annuity factor	4.3311	2/	4.3311	2/	4.3311	2/	4.3311	2/	4.3311	2/		
3	Levelized rider EDIT regulatory liability (L1 / L2)	(93,221)		(93,221)		(93,221)		(93,221)		(93,221)		($466,105)	5/
4	One minus composite income tax rate	76.8307%	3/	76.8307%	3/	76.8307%	3/	76.8307%	3/	76.8307%	3/	76.8307%	
5	Net operating income effect (L3 x L4)	(71,622)		(71,622)		(71,622)		(71,622)		(71,622)		(358,112)	
6	Retention factor	0.7654709	4/	0.7654709	4/	0.7654709	4/	0.7654709	4/	0.7654709	4/	0.7654709	
7	Levelized rider EDIT credit (L5 / L6)	($93,566)		($93,566)		($93,566)		($93,566)		($93,566)		($467,832)	

1/ Smith Supplemental Exhibit 4, Page 1, Columns (b) and (c), Line 10.
2/ Dorgan Supplemental Exhibit 2, Schedule 1(a), Line 6.
3/ One minus composite income tax rate of 23.1693%.
4/ Dorgan Supplemental Exhibit 1, Schedule 1-2, Line 14, Column (d).
5/ Column (a) plus Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ANNUITY FACTOR FOR EDIT LIABILITY RIDER
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 2
Schedule 1(a)

Line No.	Item	Amount	
	Annuity Factor		
1	Number of years	5	1/
2	Payment per period	1	
3	After tax rate of return (L9)	6.079%	
4	Present value of 1 dollar over "number of years" with with 1 payment per year	4.2033	
5	1 plus (interest rate divided by two)	1.0304	
6	Annuity factor (L4 x L5)	4.3311	

Line No.		Capital Structure (a)		Cost Rates (b)		Overall Rate of Return (c)		Net of Tax Rate (d)	
	After Tax Rate of Return						6/		
7	Long-term debt	50.00%	2/	4.110%	4/	2.055%		1.579%	7/
8	Common equity	50.00%	3/	9.000%	5/	4.500%		4.500%	8/
9	Total	100.00%				6.555%		6.079%	

1/ Rider period recommended by Public Staff.
2/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 2, Column (a).
4/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 1, Column (g).
5/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 2, Column (g).
6/ Column (a) multiplied by Column (b).
7/ Column (c) multiplied by (One minus combined income tax rate of 23.1693%).
8/ Amount from Column (c).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF LEVELIZED FEDERAL PROVISIONAL EDIT RIDER CREDIT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 2
Schedule 2

Line No.	Item	Year 1 Revenue Requirement (a)		Total Revenue Requirement (b)
1	Total NC retail regulatory liability to be amortized	($110,315)	1/	
2	Annuity factor	0.9714	2/	
3	Levelized rider EDIT regulatory liability (L1 / L2)	(113,563)		($113,563)
4	One minus composite income tax rate	76.8307%	3/	76.8307%
5	Net operating income effect (L3 x L4)	(87,251)		(87,251)
6	Retention factor	0.7654709	4/	0.7654709
7	Levelized rider EDIT credit (L5 / L6)	($113,983)		($113,983)

1/ Smith Supplemental Exhibit 4, Page 1, Column (e), Line 8.
2/ Dorgan Exhibit 2, Schedule 2(a), Line 6.
3/ One minus composite income tax rate of 23.1693%.
4/ Dorgan Supplemental Exhibit 1, Schedule 1-2, Line 14, Column (d).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF ANNUITY FACTOR FOR EDIT LIABILITY RIDER
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 2
Schedule 2(a)

Line No.	Item	Amount	
	Annuity Factor		
1	Number of years	1	1/
2	Payment per period	1	
3	After tax rate of return (L9)	6.079%	
4	Present value of 1 dollar over "number of years" with with 1 payment per year	0.9427	
5	One plus (interest rate divided by two)	1.0304	
6	Annuity factor (L4 x L5)	0.9714	

Line No.	Item	Capital Structure (a)		Cost Rates (b)		Overall Rate of Return 6/ (c)	Net of Tax Rate (d)	
	After Tax Rate of Return							
7	Long-term debt	50.00%	2/	4.110%	4/	2.055%	1.579%	7/
8	Common equity	50.00%	3/	9.000%	5/	4.500%	4.500%	8/
9	Total	100.00%				6.555%	6.079%	

1/ Rider period recommended by Public Staff.
2/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 1, Column (a).
3/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 2, Column (a).
4/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 1, Column (g).
5/ Dorgan Supplemental Exhibit 1, Schedule 4, Line 2, Column (g).
6/ Column (a) multiplied by Column (b).
7/ Column (c) multiplied by (One minus composite income tax rate of 23.1693%).
8/ Amount from Column (c).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
CALCULATION OF LEVELIZED STATE EDIT RIDER CREDIT
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 2
Schedule 3

Line No.	Item	Year 1 Revenue Requirement (a)		Total Revenue Requirement (b)
1	Total NC retail regulatory liability to be amortized	($23,998)	1/	
2	Annuity factor	0.9714	2/	
3	Levelized rider EDIT regulatory liability (L1 / L2)	(24,704)		($24,704)
4	One minus composite income tax rate	76.8307%	3/	76.8307%
5	Net operating income effect (L3 x L4)	(18,980)		(18,980)
6	Retention factor	0.7654709	4/	0.7654709
7	Levelized rider N.C. State EDIT credit (L5 / L6)	($24,795)		($24,795)

1/ Smith Supplemental Exhibit 4, Page 1, Column (d), Line 8.
2/ Dorgan Supplemental Exhibit 2, Schedule 2(a), Line 6.
3/ One minus composite income tax rate of 23.1693%.
4/ Dorgan Supplemental Exhibit 1, Schedule 1-2, Line 14, Column (d).

INDEX TO DORGAN SUPPLEMENTAL EXHIBIT 3

	Title	Schedule Number
1	COMPANY RATE BASE, AS REALLOCATED BY PUBLIC STAFF	1
2	COMPANY ADJUSTMENTS TO RATE BASE,AS REALLOCATED BY PUBLIC STAFF	1-1
3	COMPANY NET OPERATING INCOME, AS REALLOCATED BY PUBLIC STAFF	2
4	COMPANY ADJUSTMENTS TO NET OPERATING INCOME, AS REALLOCATED BY PUBLIC STAFF	2-1

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
COMPANY RATE BASE, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 3
Schedule 1-1

		North Carolina Retail Operations		
Line No.	Description	Company SWPA Per Books 1/	Company SWPA Proforma Accounting Adjustments 2/	SWPA Reallocated By Public Staff 3/
		(a)	(b)	(c)
1	Electric plant in service	$18,662,205	$ 464,966	$19,127,171
2	Accumulated depreciation and amortization	(7,983,917)	(56,354)	(8,040,272)
3	Net electric plant (L1 + L2)	$10,678,288	$408,612	$11,086,900
4	Materials and supplies	750,939	(172,187)	578,751
5	Working capital investment	(376,636)	861,824	485,187
6	Accumulated deferred taxes	(1,318,934)	(201,443)	(1,520,378)
7	Operating reserves	(54,448)	-	(54,448)
8	Construction work in progress	102,930	(102,930)	(0)
9	Total Original Cost Rate Base (Sum of L3 through L8)	$9,782,137	$793,875	$10,576,012

1/ Per cost of service study recommended by Public Staff witness McLawhorn.
2/ Dorgan Supplemental Exhibit III, Schedule 1-1, Line 36.
3/ Column (a) plus Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
COMPANY ADJUSTMENTS TO RATE BASE,
AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 3
Schedule 1-1

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)
1		Annualize retail revenues for current rates	-	-	-	-	-	-	-	-
2		Update fuel costs to proposed rate	-	-	-	-	-	-	-	-
3	*	Normalize for weather	-	-	-	-	-	-	-	-
4	*	Annualize revenues for customer growth	-	-	-	-	-	-	-	-
5		Eliminate unbilled revenues	-	-	-	-	-	-	-	-
6		Adjust for costs recovered through non-fuel riders	(969,466)	157,536	(157,051)	(150,987)	89,768	-	-	(1,030,200)
7		Adjust O&M for executive compensation	-	-	-	-	-	-	-	-
8		Annualize depreciation on year end plant balances	-	-	-	-	-	-	-	-
9		Annualize property taxes on year end plant balances	-	-	-	-	-	-	-	-
10	*	Adjust for post test year additions to plant in service	1,434,886	(126,463)	-	18,763	(55,998)	-	(102,930)	1,168,257
11	*	Amortize deferred environmental costs	-	-	-	383,752	(88,913)	-	-	294,839
12		Annualize O&M non-labor expenses	-	-	-	-	-	-	-	-
13	*	Normalize O&M labor expenses	-	-	-	-	-	-	-	-
14		Update benefits costs	-	-	-	-	-	-	-	-
15	*	Levelize nuclear refueling outage costs	-	-	-	-	-	-	-	-
16	*	Amortize rate case costs	-	-	-	2,670	(619)	-	-	2,051
17		Adjust aviation expenses	-	-	-	-	-	-	-	-
18		Adjust for approved regulatory assets and liabilities	-	-	-	(83,851)	19,428	-	-	(64,423)
19	*	Adjust for Merger Related Costs	(453)	351	-	-	-	-	-	(102)
20	*	Amortize Severance Costs	-	-	-	21,655	(5,017)	-	-	16,637
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	-	-

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
COMPANY ADJUSTMENTS TO RATE BASE,
AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Line No.		Description	EPIS (Col. 1)	Accum Deprec (Col. 2)	Materials & Supplies (Col. 3)	Working Capital (Col. 4)	ADIT (Col. 5)	Operating Reserves (Col. 6)	CWIP (Col. 7)	Rate Base (Col. 8)
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	-	-
23	*	Adjust cash working capital	-	-	-	(21,145)	-	-	-	(21,145)
24		Adjust coal inventory	-	-	(11,603)	-	-	-	-	(11,603)
25	*	Adjust for credit card fees	-	-	-	-	-	-	-	-
26		Adjust Depreciation for new rates	-	(87,779)	-	-	-	-	-	(87,779)
27		Adjust vegetation management expenses	-	-	-	-	-	-	-	-
28		Adjust reserve for end of life nuclear costs	-	-	-	-	-	-	-	-
29	*	Update deferred balance and amortize storm costs	-	-	-	604,202	(139,989)	-	-	464,213
30		Adjust other revenue	-	-	-	-	-	-	-	-
31		Adjust for change in NCUC Reg Fee	-	-	-	-	-	-	-	-
32	*	Reflect retirement of Asheville Steam Generating Plant	-	-	(7,021)	63,888	(14,802)	-	-	42,065
33		Adjust for CertainTeed payment obligation	-	-	-	-	-	-	-	-
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	3,488	22,876	(5,300)	-	-	21,063
35		Adjust Purchased Power	-	-	-	-	-	-	-	-
36		Total adjustments	$ 464,966	$ (56,354)	$ (172,187)	$ 861,824	$ (201,443)	$ -	$ (102,930)	$ 793,875

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
COMPANY NET OPERATING INCOME, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Public Staff
Dorgan Supplemental Exhibit 3
Schedule 2

		North Carolina Retail Operations		
Line No.	Description	Company SWPA Per Books 1/	Company SWPA Proforma Accounting Adjustments 2/	SWPA Reallocated By Public Staff 3/
		(a)	(b)	(c)
1	Electric operating revenue	$ 3,657,316	$ (296,473)	$ 3,360,843
	Electric operating expenses:			
	Operation and maintenance:			
2	Fuel used in electric generation	881,642	(29,976)	851,667
3	Purchased power	158,032	(1,944)	156,088
4	Other operation and maintenance expense	1,047,158	(181,480)	865,678
5	Depreciation and amortization	665,546	278,306	943,851
6	General taxes	101,487	329	101,816
7	Interest on customer deposits	7,971	-	7,971
8	Net income taxes	115,441	(66,803)	48,639
9	Amortization of investment tax credit	(2,111)	(1,468)	(3,580)
10	Total electric operating expenses (Sum of L2 through L9)	2,975,166	(3,036)	2,972,130
11	Operating income (L1 minus L10)	$ 682,151	$ (293,437)	$ 388,714

1/ Per cost of service study recommended by Public Staff witness McLawhorn.
2/ Dorgan Supplemental Exhibit III, Schedule 2-1, Line 36.
3/ Column (a) plus Column (b).

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
COMPANY ADJUSTMENTS TO NET OPERATING INCOME, AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	Income Taxes (at Composite Rate of 23.1693005%) (Col. 7)	Amortization of ITC (Col. 8)	Operating Income
1		Annualize retail revenues for current rates	(201,667)	-	-	(744)	-	-	(46,552)	-	(154,370)
2		Update fuel costs to proposed rate	-	11,449	-	-	-	-	(2,653)	-	(8,796)
3	*	Normalize for weather	(72,510)	(20,432)	-	(268)	-	-	(12,004)	-	(39,806)
4	*	Annualize revenues for customer growth	(2,159)	(2,471)	-	(8)	-	-	74	-	246
5		Eliminate unbilled revenues	11,826	-	-	-	-	-	2,740	-	9,086
6		Adjust for costs recovered through non-fuel riders	(27,808)	(18,522)	-	(135,449)	(58,102)	(6,392)	62,917	-	127,740
7		Adjust O&M for executive compensation	-	-	-	(2,387)	-	-	553	-	1,834
8		Annualize depreciation on year end plant balances	-	-	-	-	40,944	-	(9,486)	(1,468)	(29,989)
9		Annualize property taxes on year end plant balances	-	-	-	-	-	4,032	(934)	-	(3,098)
10	*	Adjust for post test year additions to plant in service	-	-	-	-	61,382	4,931	(15,364)	-	(50,949)
11	*	Amortize deferred environmental costs	-	-	-	-	95,938	-	(22,228)	-	(73,710)
12		Annualize O&M non-labor expenses	-	-	-	1,336	-	-	(310)	-	(1,027)
13	*	Normalize O&M labor expenses	-	-	-	(19,699)		(1,156)	4,832	-	16,023
14		Update benefits costs	-	-	-	(6,327)	-	-	1,466	-	4,861
15	*	Levelize nuclear refueling outage costs	-	-	-	(6,190)	-	-	1,434	-	4,756
16	*	Amortize rate case costs	-	-	-	701	-	-	(162)	-	(539)
17		Adjust aviation expenses	-	-	-	(1,445)	-	(18)	339	-	1,124
18		Adjust for approved regulatory assets and liabilities	-	-	-	1,603	(3,489)	5	436	-	1,445
19	*	Adjust for Merger Related Costs	-	-	-	(4,021)	(180)	(53)	986	-	3,268
20	*	Amortize Severance Costs	-	-	-	(24,025)	-	-	5,566	-	18,458
21		Adjust NC income taxes for rate change	-	-	-	-	-	-	(2,228)	-	2,228

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1219
North Carolina Retail Operations
COMPANY ADJUSTMENTS TO NET OPERATING INCOME,
AS REALLOCATED BY PUBLIC STAFF
For the Test Year Ended December 31, 2018
(Dollar Amounts Expressed in Thousands)

Line No.		Description	Electric Operating Revenue (Col. 1)	Fuel Used in Electric Generation (Col. 2)	Purchased Power and Net Interchange (Col. 3)	Other O&M Expense (Col. 4)	Depreciation and Amortization (Col. 5)	General Taxes (Col. 6)	Income Taxes (at Composite Rate of 23.1693005%) (Col. 7)	Amortization of ITC (Col. 8)	Operating Income
22	*	Synchronize interest expense with end of period rate base	-	-	-	-	-	-	392	-	(392)
23	*	Adjust cash working capital	-	-	-	-	-	-	96	-	(96)
24		Adjust coal inventory	-	-	-	-	-	-	-	-	-
25	*	Adjust for credit card fees	-	-	-	5,307	-	-	(1,230)	-	(4,078)
26		Adjust Depreciation for new rates	-	-	-	-	87,779	-	(20,338)	-	(67,441)
27		Adjust vegetation management expenses	-	-	-	5,746	-	-	(1,331)	-	(4,415)
28		Adjust reserve for end of life nuclear costs	-	-	-	-	(260)	-	60	-	200
29	*	Update deferred balance and amortize storm costs	-	-	-	-	43,157	-	(9,999)	-	(33,158)
30		Adjust other revenue	(4,155)	-	-	(5)	-	-	(962)	-	(3,188)
31		Adjust for change in NCUC Reg Fee	-	-	-	(234)	-	-	54	-	180
32	*	Reflect retirement of Asheville Steam Generating Plant	-	-	-	(6,397)	(301)	(1,021)	1,788	-	5,930
33		Adjust for CertainTeed payment obligation	-	-	-	4,939	-	-	(1,144)	-	(3,794)
34	*	Amortize deferred balance Asheville Combined Cycle	-	-	-	6,087	11,438	-	(4,060)	-	(13,465)
35		Adjust Purchased Power	-	-	(1,944)	-	-	-	450	-	1,493
36		Total adjustments	$ (296,473)	$ (29,976)	$ (1,944)	$ (181,480)	$ 278,306	$ 329	$ (66,803)	$ (1,468)	$ (293,437)

Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-2, Sub 1219

April 13, 2020

Exhibit JMV-TF-1

BACKGROUND AND QUALIFICATIONS
JAMES M. VAN NOSTRAND

Q. Please state your name, title and employer.

A. My name is James M. Van Nostrand. I am an Energy Policy Expert for EQ Research, a consulting firm based out of Cary, North Carolina. I am also a Professor of Law at the West Virginia University College of Law, where I teach energy and environmental law and Direct the Center for Energy and Sustainable Development.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Please state your educational and professional experience.

A. I received my B.A. degree in economics from the University of Northern Iowa in 1976 and a law degree from the University of Iowa in 1979. While I was employed at the New York Public Service Commission, I studied economics at SUNY Albany, and received an M.A. in economics in 1984 from that institution. I received an LL.M. degree in environmental law from the Elisabeth Haub School of Law at Pace University in 2011.

From 1980 to 1985, I worked for the New York Public Service Commission, first as an Assistant to the Commission for Opinions and Review and then as Assistant to Chairman Paul L. Gioia. In 1985, I joined the law firm of Perkins Coie in its Bellevue, Washington office, where I worked for 14 years, becoming a partner in 1990. In 1999, I joined the Seattle office of the Portland, Oregon-based law firm of Stoel Rives, as a partner in the firm’s energy and telecommunications group. I rejoined Perkins Coie in 2006, as a partner in the firm’s environmental and natural resources practice group in its Portland, Oregon office. Beginning in 2007, I transitioned into law school teaching, which included appointments to the adjunct faculty at Lewis & Clark Law School (Spring 2007), and visiting professor positions at the University of Tennessee College of Law (Fall 2007) and the University of Iowa College of Law (Spring 2008). In May 2008, I joined the adjunct faculty at Pace Law School and became Executive Director of the Pace Energy and Climate Center, an energy and environmental research and policy organization active in administrative proceedings in New York and the Northeast. In July 2011, I joined the faculty at the West Virginia University College of Law, and became Director of the newly established Center for Energy and Sustainable Development. Most recently, I served as a Senior Policy Advisor to Chairman John R. Rhodes of the New York Public Service Commission (on a part-time consulting basis) from January 2018 through June 2019.

Q. Have you previously testified before utility regulatory agencies?

A. Yes, I have testified in the following cases:

New York Public Service Commission: Niagara Mohawk Power Corporation, Case 10-E-0050 (testimony on behalf of Pace Energy & Climate Center, Natural Resources Defense Council on non-wires alternatives (including distributed generation and energy efficiency) and decoupling)

Colorado Public Utility Commission:

- In the Matter of Commission Consideration of Public Service Company of Colorado's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act," Docket No. 10M 245E (testimony on behalf of Noble Energy, Inc., Chesapeake Energy Corporation and Encana Oil & Gas (USA) regarding foreseeable requirements of Clean Air Act)
- In the Matter of the Application of Public Service Company of Colorado for Approval of its Solar*Connect Program, Proceeding No. 16A-0055E, (testimony on behalf of the Energy Freedom Coalition of America)
- Public Service Company of Colorado: In the Matter of the Application for Approval of the 600 MW Rush Creek Wind Project Pursuant to Rule 3660(h) Certificate of Public Convenience and necessity for the Rush Creek Wind Farm, and a Certificate of Public Convenience and Necessity for the 345 kV Rush Creek to Missile Site Generation Tie Transmission Line and Associated Findings of Noise and Magnetic Field Reasonableness, Proceeding No. 16A-0117E (testimony on behalf of Sustainable Power Group, LLC (sPower))

Hawaii Public Utility Commission: In the Matter of the Application of Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company, Limited, and NextEra Energy Inc. for Approval of the Proposed Change of Control and Related Matters, Docket No. 2015-0022 (testimony on behalf of the Alliance for Solar Choice (TASC) in opposition to proposed merger)

South Carolina Public Service Commission: Petition of the Office of Regulatory Staff to Establish Generic Proceeding Pursuant to the Distributed Energy Resource Program Act, Act No. 236 of 2014, Ratification No. 241, Senate Bill No. 1189, Docket No. 2014-24-E (testimony on behalf of TASC)

West Virginia Public Service Commission: Appalachian Power Company and Wheeling Power Company, both dba American Electric Power, Petition for Consent and Approval of Mitchell Plant by Wheeling Power Company, Case No. 14-0546-E-PC (testimony on behalf of Consumer Advocate Division regarding the environmental liabilities associated with the Conner Run coal ash impoundment)

Q. Have you previously testified before the North Carolina Utilities Commission ("the Commission")?

A. No.

Q. In addition to cases in which you have testified, have you participated in regulatory cases as an attorney?

A. Yes, during my 22 years in private law practice in the Pacific Northwest, I represented investor-owned utilities in dozens of rate proceedings before state utility regulatory agencies in Washington, Oregon, Idaho, Wyoming, California, Utah, and Alaska. My clients included Puget Sound Energy, PacifiCorp (including Pacific Power & Light and Utah Power), Northwest Natural Gas, Cascade Natural Gas, and Portland General Electric. I also represented Puget Sound Energy in a transmission rate proceeding before the Federal Energy Regulatory Commission. In addition to rate proceedings, I handled the regulatory approvals for several utility mergers and acquisitions, including Macquarie's acquisition of Puget Sound Energy, MidAmerican Energy Holdings Company's acquisition of

PacifiCorp, MDU Utilities' acquisition of Cascade Natural Gas Company, ScottishPower's acquisition of PacifiCorp, Qwest's acquisition of US WEST, and Puget Sound Power & Light Company's acquisition of Washington Natural Gas Company. In recognition of my achievements as an energy attorney in private practice, I received the Energy Bar Association's State Regulatory Practitioner of the Year Award in 2007. Following my transition into law school teaching, I was also involved in proceedings on behalf of Pace and Natural Resources Defense Council in proceedings before the New York Public Service Commission while I was Executive Director of the Pace Energy & Climate Center.

A copy of my current curriculum vitae is attached.

James M. Van Nostrand

West Virginia University College of Law
P.O. Box 6130
Morgantown, WV 26506-6130
(304) 293-4694 (Office)
E-Mail: james.vannostrand@mail.wvu.edu

Current Position

Professor of Law
Director, Center for Energy and Sustainable Development July 2011 – present

West Virginia University College of Law

The Center for Energy and Sustainable Development conducts objective, unbiased research and policy analyses; provides a forum for issues to be explored by the various stakeholders; and promotes policies that strike a balance between the development of energy resources and protection of the environment.

Keyes & Fox LLP January 2016 – December 2017; July 2019 - present

Of Counsel with a national law firm specializing in distributed generation and renewable energy law, with offices in Oakland, CA, Cary, NC and Denver, CO.

EQ Research LLC January 2015 – December 2017; July 2019 - present

Energy Policy Expert on renewables and distributed energy resources for North Carolina-based consulting firm.

Prior Employment Experience

Consultant on Energy Policy (New York) January 2018 – June 2019

Van Nostrand Energy & Environmental Consulting LLC

Under consulting agreement with the New York State Energy and Research Development Authority (NYSERDA), served as Senior Policy Advisor to Chairman John B. Rhodes of the New York Public Service Commission

Executive Director May 2008 – July 2011

Pace Energy and Climate Center
Elisabeth Haub School of Law at Pace University

Executive Director of multi-disciplinary research, policy and advocacy organization focused on energy and sustainability issues and climate change law and policy; the Center is active in energy and sustainability policy matters in New York and throughout the Northeast; the Center combines objective, unbiased research and legal and policy analysis with effective advocacy in achieving necessary market and regulatory reforms supportive of renewable energy, energy efficiency and clean distributed generation.

Perkins Coie LLP

Bellevue, WA office October 1985 – November 1999
Portland, OR office July 2006 – February 2009

Partner (associate prior to January 1990) in the energy and regulatory practice in Northwest's largest law firm; practice emphasis on electricity and gas regulation, utility mergers and acquisitions, telecommunications and administrative law; recipient of ***Energy Bar Association 2007 State Regulatory Practitioner of the Year***; included in "The Best Lawyers in America" (Wood/White, 10th, 11th, 12th and 13th editions)

Clients/Representative Transactions: PacifiCorp retail rate proceedings (WA); Puget Sound Energy transmission rate proceeding (FERC), retail rate proceedings (WA); Portland General Electric retail rate proceedings (OR); Northwest Natural Gas Co. retail rate proceedings (WA and OR); Cascade Natural Gas Co. retail rate proceedings

James M. Van Nostrand (continued)

(WA and OR); regulatory approval for Macquarie acquisition of Puget Sound Energy (WA); regulatory approval for MDU Resources Group acquisition of Cascade Natural Gas Co. (WA and OR); regulatory approval for ScottishPower acquisition of PacifiCorp (WA, OR, ID, UT, CA, and WY); regulatory approval for Qwest acquisition of U S WEST (WA); regulatory approval for merger of Puget Sound Power & Light Company and Washington Natural Gas Company to form Puget Sound Energy (WA).

Stoel Rives LLP, Seattle and Portland offices November 1999 – July 2006

Partner in the Energy & Telecommunications practice group, with practice emphasis on electricity and gas regulation, utility mergers and acquisitions, telecommunications and administrative law

Clients/Representative Transactions: PacifiCorp retail rate proceedings (WA, OR, ID, CA, UT and WY); Portland General Electric retail rate proceedings (OR); Northwest Natural Gas Company retail rate proceedings (OR); Cascade Natural Gas Company retail rate proceedings (OR); regulatory approval for MidAmerican Energy Holding Company acquisition of PacifiCorp (WA and ID).

New York Public Service Commission, Albany, New York July 1980 – September 1985

Assistant to the Commission for Opinions and Review (3 ½ years); Assistant to the Chairman (1 ½ years); legal and policy analysis, opinion-writing for commissioners, Chairman in utility rate cases

Education

LL.M., Environmental Law (Climate Change Track), Elisabeth Haub School of Law at Pace University (2011)

M.A., Economics, State University of New York at Albany (1985)

J.D., University of Iowa College of Law (With High Honors) (1979)
Order of the Coif; Class Rank 9/201
Associate editor, *Journal of Corporation Law*

B.A., Economics, University of Northern Iowa (With Highest Honors) (1976)

Teaching Experience

West Virginia University College of Law, Morgantown, WV – Professor, July 2016 to Present (Associate Professor, July 2011 to July 2016) – Teach various energy and environmental courses (Energy Regulation, Markets & the Environment, Science & Technology of Energy, Siting and Permitting of Energy Facilities, Environmental Protection Law, Alternative Energy & Renewable Fuels, Clean Air Act Seminar, Legislation & Regulation)

University of Pittsburgh School of Law, Pittsburgh, PA – Adjunct Faculty, Spring 2015 and Spring 2016 – Taught Environmental Law

University of Iowa College of Law, Iowa City, IA – Visiting Professor, Spring 2008 – Taught courses in Energy Law & Regulated Industries, Administrative Law

University of Tennessee College of Law, Knoxville, TN – Visiting Professor, Clayton Center for Entrepreneurial Law, Fall 2007 – Taught courses in Energy Law & Regulated Industries, Business Associations

Lewis & Clark Law School, Portland, OR – Adjunct Faculty, Spring 2007, taught 3-credit course in Energy Law and Economic Regulation of Utilities

Willamette University, Atkinson Graduate School of Management, Utility Management Certificate Program – Assisted in developing curriculum for MBA-level program for utility managers; instructor, 2005 to Present

Northeast Bioenergy and Bioproducts Master Teaching Training Workshop, Pace University, New York, NY – Lecturer on Renewable Energy and Biofuels, July 2011

James M. Van Nostrand (continued)

Publications

"The Trump Administration's Futile Efforts to Prop Up the Declining U.S. Coal Industry," Trends, American Bar Association Section on Environment, Energy & Resources (Oct/Nov 2019)

"Quantifying the Resilience Value of Distributed Energy Resources," 35 FLA. S. U. J. LAND USE & ENVTL. L. 1 (2020)

Using Emergency Powers to Provide Financial Assistance to Coal and Nuclear Plants," 11 KY. J. EQUINE, AGRIC. & NAT. RESOURCES L. 191 (2019)

"Protecting Consumers via Tariff Regulation," Chapter 60, ELGAR ENCYCLOPEDIA OF ENVIRONMENTAL LAW, VOLUME: ENERGY LAW AND THE ENVIRONMENT, International Union for Conservation of Nature (IUCN), Edward Elgar Publishing (to be published Spring 2020)

"Production and Delivery of Bioenergy Fuels," LEGAL PATHWAYS TO DEEP DECARBONIZATION IN THE UNITED STATES, (edited by Michael B. Gerrard and John C. Dernbach), Environmental Law Institute (2018)

"Here's Why Trump's New Strategy to Keep Ailing Coal and Nuclear Plants Makes No Sense," The Conversation (June 2018) (republished in several newspapers throughout the country)

"To Draw Jobs, WV Needs Ability to Give Manufacturers a Break on Electricity," (Op-Ed piece) CHARLESTON GAZETTE-MAIL (April 29, 2018)

"Planned Sale of Pleasants Plant a Step Backward," (Op-Ed piece) CHARLESTON GAZETTE-MAIL (September 23, 2017)

"Keeping the Fox from Managing the Henhouse: Why Incumbent Utilities Should Not Be Allowed to Operate the Distribution System Platform," 8 GEO. WASH. J. ENERGY AND ENVTL. L. 23 (2017)

"Why the U.S. Coal Industry and Its Jobs Are Not Coming Back," YALE ENVIRONMENT 360 (December 1, 2016)

"Expanding Economic Opportunities for West Virginia under the Clean Power Plan," July 2016 (with E. Hansen & J. James)

"Thinking it Through," WVU MAGAZINE, West Virginia University (Fall 2015)

"Keeping the Lights on During Superstorm Sandy: Climate Change Adaptation and the Resiliency Benefits of Distributed Generation," 23 N.Y.U. ENVTL. L.J. 92 (2015)

"Getting to Utility 2.0: Rebooting the Retail Electric Utility in the U.S.," 6 SAN DIEGO J. CLIMATE & ENERGY L. 149 (2015)

"The Clean Power Plan and West Virginia: Compliance Options and New Economic Opportunities," June 2015 (with B. Argetsinger, E. Hansen & J. James)

"Carbon Dioxide Emission Reduction Opportunities for the West Virginia Power Sector," Discussion Paper, October 2014 (with B. Argetsinger, E. Hansen, J. Simcoe)

"EPA Regulation of Carbon Dioxide Emissions from Existing Power Plants under Section 111(d) of the Clean Air Act," written materials to accompany presentation at 2014 Kentucky Mineral Law Conference, Energy & Mineral Law Foundation

"What's Coming Down the Tracks for Midstream Operators in 2014? Emerging Issues and Regulatory Update for Crude Oil by Rail," chapter for proceedings of 35th Annual Institute, Energy & Mineral Law Foundation

"Cogeneration (CHP) Could Stimulate Demand for natural Gas Throughout Region," Bowles Rice LLP VIEWS AND VISIONS, Summer 2014

"An Energy and Sustainability Roadmap for West Virginia," 115 W. VA. L. REV. 885 (2013)

James M. Van Nostrand (continued)

"Subject to Debate: Economics, Energy & the Environment," UNI BUSINESS (Alumni Magazine of the College of Business Administration, University of Northern Iowa (2013), at 10-11

"Energy and Environmental Justice: How States Can Integrate Environmental Justice into Energy-Related Proceedings," 61 CATH. U. L. REV. 701 (2012)

Chapter 19, "Biofuels", THE LAW OF CLEAN ENERGY: EFFICIENCY AND RENEWABLES, edited by Michael B. Gerrard, American Bar Association, 2011 (with A. Hirschberger).

"Parametric Insurance: Using Objective Measures to Address the Impacts of Natural Disasters and Climate Change," 23 ENVTL. CLAIMS J. 227, (2011) (with J. Nevius)

"Implications of a Federal RPS: Will It Supplement or Supplant the Existing State Initiatives?" 41 U. TOLEDO L. REV. 853 (2010) (with A. Hirschberger)

"Legal Issues in Financing Energy Efficiency," 2 GEO. WASH. J. ENERGY AND ENVTL. L. 1 (2011)

"New York's Roadmap for Reducing Greenhouse Gases in the Transportation Sector," 2011 U. ILL. L. REV. 475 (2011) (with A. Hirschberger).

"Preserving the Public Interest through Alternative Dispute Resolution of Utility Retail Rate Cases," 27 PACE ENVTL. L. REV. 227 (2009) (with E. Honaker)

"Constitutional Limitations on the Ability of States to Rehabilitate Their Failed Electric Utility Restructuring Plans," 31 SEATTLE U. L. REV. 593 (2008)

"Representing the Utility in State Retail Rate Proceedings," *The Best Practices of Leading Energy Lawyers: Successful Strategies and Best Practices for Dealing with Energy-Related Legal Issues*, Aspatore, Inc. (2007)

"The Standard for Setting Utility Rates in Wyoming: Restoring the Required Balance Between Investors and Customers," 4 WYO. L. REV. 245 (2004)

Co-Editor-In-Chief, *Washington Administrative Law Practice Manual*, Butterworth

"The Legislative Evolution of Title I of the Public Utilities Regulatory Policies Act of 1978: A Study in Compromise," 5 J. CORP. L 105 (1979)

"Betterment Accounting: A Requiem by the SEC?" 4 J. CORP. L. 213 (1978)

Conferences Organized

"Leaving No One Behind: Ensuring A Fair Transition for Workers and Communities," West Virginia Center on Climate Change, West Virginia Center on Budget and Policy, Charleston, WV (February 2020)

"Climate Change and Public Health: Addressing the Growing Crisis," West Virginia College of Law, West Virginia Center on Climate Change, Mid-Atlantic Regional Public Health Training Center, Morgantown, WV (September 2019)

"Climate Change Issues Update," West Virginia College of Law and Friends of Blackwater Allegheny Highlands Climate Change Impact Initiative, Morgantown, WV (December 2018)

"The Emerging Energy Economy for West Virginia," West Virginia College of Law and Appalachian Stewardship Foundation, Morgantown, WV (October 2017)

"Building a Resilient West Virginia: Taking Control of the Mountain State's Future," West Virginia College of Law and John D. Rockefeller IV School of Policy and Politics, Morgantown, WV (April 2016)

"The Intersection of Water & Energy: Implications of Water Protection on Energy Production," West Virginia College of Law, Morgantown, WV (April 2015)

James M. Van Nostrand (continued)

"Regulation of CO_2 Emissions from Power Plants: Flexibility and the Path Forward for Coal Dependent States," West Virginia University College of Law, Morgantown, WV (February 2014)

"Natural Gas as the Bridge to Sustainability and Economic Growth: Exploring Policies to Stimulate the Use of Shale Gas Resources," West Virginia University College of Law, Morgantown, WV (April 2013)

"Drilling Down on Regulatory Challenges: Balancing Preservation and Profitability in the Development of Shale Gas Resources," West Virginia University College of Law, Morgantown, WV (October 2011)

International Presentations

"Getting to Utility 2.0: Merging Technological Innovation and Capital Deployment with the Energy Market Regulatory Paradigm," IUCN Academy of Environmental Law, 12th Annual Colloquium, Universitat Rovira i Virgili, Tarragona, Catalonia, Spain (July 2014)

"Distributed Generation as a Climate Change Strategy," London Climate Change Symposium, Oxford and Cambridge University Club, London, England (June 2013)

"The Potential Role of Natural Gas in Poland's Energy Planning," Guest Lecture at Szkola Glowna Gospodarstwa Wiejskiego (SGGW), Warsaw, Poland (June 2013)

"Development Trends and Importance of Natural Gas in the Economy," Drilling Oil-Gas AGH 2013, Akademia Gorniczo-Hutnicza (AGH), Krakow, Poland (June 2013)

Two-day executive course for national stakeholders on Climate Change Law and Policy, with Professor Nicholas A. Robinson, sponsored by the Environmental Education Center of Ilia State University (Tbilisi Georgia), the Center for Environmental Legal Studies of Pace Law School, and the International Union for the Conservation of Nature (IUCN), Ilia State University Institute of Alpine Ecology, Stephantsminda, Georgia (May 2011)

"Lessons Learned From Emissions Trading Under the Northeast Regional Greenhouse Gas Initiative (RGGI)," Green Korea 2010 Conference, Seoul, South Korea (September 2010)

Testimony

"Promoting Solar on Former Mine Lands," West Virginia House of Delegates, Interim Hearing of the Energy Committee, Charleston, WV (November 2019)

EPA Public Hearing on Repealing the Clean Power Plan, Charleston, WV (November 2017)

West Virginia Public Service Commission, Public Hearing on Proposed Transfer of Pleasants Station, Case No. 17-0296-E-PC, Morgantown, WV (September 2017)

"Impacts of EPA Regulations on West Virginia's Coal Production, Employment, Air Quality, Community Wellness, Climate Risk and Local Government Operations," Testimony to U.S. Senate Committee on Environment and Public Works, Subcommittee on Clean Air and Nuclear Safety, Field Hearing, Logan, WV (October 2016)

"Regional Impacts of EPA Carbon Regulations: The Case of West Virginia," Testimony to U.S. Senate Committee on Environment and Public Works, Field Hearing, Beckley, WV (March 2015)

Testimony to West Virginia House of Delegates, Judiciary Committee, regarding HB 2001 (repeal of West Virginia Alternative and Renewable Energy Portfolio Standard) (January 2015)

"Regulatory Hurdles to Cost Recovery for Coal Plant Maintenance and Upgrades," Testimony to U.S. Senate Energy and Natural Resources Committee, Subcommittee on Public Lands, Forests and Mining, Field Hearing, Morgantown, WV (September 2013)

James M. Van Nostrand (continued)

Other Recent Presentations

"Recent Developments in Quantifying the Resilience Value of Distributed Energy Resources," Fourth Annual Research Roundtable on Energy Regulation, Technology, and Transaction Costs: Cross-Cutting Perspectives, Northwestern Pritzker School of Law, Northwestern Center on Law, Business, and Economics, Institute for Regulatory Law & Economics, Chicago, IL (November 2019)

"The Use of Renewable Portfolio Standards, Net-Zero Carbon Goals, and Zero Emissions Credits in Reshaping the U.S. Power Industry," Energy & Mineral Law Foundation, Kentucky Mineral Law Conference, Lexington, KY (October 2019)

"Quantifying the Resilience Value of Distributed Energy Resources," Energy Policy Research Conference, Boise, ID (September 2019)

"Variations on Community Solar Program Design," Community Solar Power Summit, Philadelphia, PA (July 2019)

"Incorporating Solar Energy into the Appalachian Grid," Energy & Mineral Law Foundation, 40th Annual Institute, Washington, DC (June 2019)

"Solar Policy Priorities for West Virginia," West Virginia Solar United Neighbors, 4th Annual Solar Congress, Charleston, WV (April 2019)

"Quantifying the Resilience Value of Distributed Energy Resources," Panel Discussion on Energy Resilience, Florida State University, Tallahassee, FL (January 2019)

"Using Emergency Powers to Provide Financial Assistance to Coal and Nuclear Plants," Energy & Mineral Law Foundation, Kentucky Mineral Law Conference, Lexington, KY (October 2018)

"The (Dim) Prospects for Coal's Ability to Compete in Wholesale Electricity Markets," Reed Smith LLP, Pittsburgh, PA (December 2018)

"The Impact of a Jobs First Agenda: A New Energy Economy," Community Discussion Series, Wheeling Academy of Law and Science, Wheeling, WV (October 2018)

"The Cost of Cutting the Cord: Distributed Energy Resources and Exit Fees," Energy Policy Research Conference, Deer Valley, UT (September 2017)

"Executive Powers to Set Aside the Law: Department of Energy Authority under the Federal Power Act," West Virginia College of Law, Continuing Legal Education, *Government Powers and Limitations*, Morgantown, WV (October 2017)

"Introduction to U.S. Energy Policy Making," Lecture to Shenhua Delegation, National Research Center for Coal and Energy, Morgantown, WV (August 2017)

"Protecting the Environment without an Environmental Protection Agency," Earth Day 2017, West Virginia University, Morgantown, WV (April 2017)

"Roundtable: The State of Low Carbon Technology," Reed Smith LLP, Pittsburgh, PA (February 2017)

"An Ethical, Sustainable Energy Industry—A Panel Discussion," Appalachian Public Interest Environmental Law Conference, Knoxville, TN (October 2016)

"An Ethical, Sustainable Energy Industry," Panel Discussion, Howard H. Baker Jr. Center for Public Policy, Knoxville, TN (October 2016)

"The Role of Renewable Energy and Energy Efficiency under the Clean Power Plan," Panel Presentation on "Renewables—Coming to a Grid Near You!" Energy & Mineral Law Foundation, Kentucky Mineral Law Conference, Lexington, KY (October 2016)

James M. Van Nostrand (continued)

"An Update on Energy Issues in West Virginia," West Virginia Agricultural Land Protection Authority, Davis, WV (October 2016)

"New Clean Air Standards and Sustainable Development in West Virginia," West Virginia State University, Keynote Speaker Earth Day 2016, Institute, WV (April 2016)

"Trends and Outlook for Workers in the Coal Industry and Coal-Reliant Communities," Brookings Institution and Columbia Center on Global Energy Policy Workshop, "Building a Better Future for Coal Workers and Their Communities," Washington, DC (November 2015)

"Speaking Truth to Power: West Virginia's Options for Responding to EPA's Clean Power Plan," Wheeling Jesuit University, Appalachian Institute, Wheeling, WV (October 2015)

"The. U.S. Clean Power Plan: What Are Our Options?" Allegheny Highlands Climate Change Impacts Initiative 2015 Climate Change Conference, Blackwater Falls State Park, WV (October 2015)

"EPA's Clean Power Plan: An Overview and Compliance Options for West Virginia," Rotary Club of Charleston, WV (October 2015)

"Response of the Coal-Dependent States to the Clean Power Plan: Litigate, Legislate, Retaliate or Innovate?" Pittsburgh Coal Conference, Pittsburgh, PA (October 2015)

"EPA's Clean Power Plan: An Overview and Compliance Options for West Virginia," Reed Smith Teleseminar: The Coal Industry, Pittsburgh, PA (August 2015)

"Saving Lives When the Grid Goes Down: Improving the Resilience of the Healthcare System in the Face of Extreme Weather Events," National Association of County & City Health Officials (NACCHO) Preparedness Summit, Atlanta, GA (April 2015)

"Regulation of CO_2 Emissions from Existing Power Plants under Section 111(d) of the Clean Air Act: The View from a Coal-Dependent State," Energy Finance 2015 Conference, Institute for Policy Integrity and the Institute for Energy Economics and Financial Analysis, , NYU School of Law, New York, NY (March 2015)

"(Relatively) Green and Clean: Environmental Impacts of Renewable Electricity Generating Projects," American Law Institute (ALI) CLE, Environmental Law (co-sponsored by the Environmental Law Institute (ELI)), Washington, DC (February 2015)

"Regulation of CO_2 Emissions from Existing Power Plants: The Clean Power Plan and Considerations for West Virginia," Energy Efficient West Virginia, Charleston, WV (December 2014)

Closing Remarks, "Energy for the Power of 32," Sustainable Pittsburgh, Pittsburgh, PA (December 2014)

"Utility of the Future and the Business Model under a New Regulatory Paradigm," University of San Diego School of Law, Sixth Annual Climate and Energy Law Symposium, San Diego, CA (November 2014)

"Clean Power and Carbon: A View from the States, Regulation of CO_2 Emissions from Existing Power Plants under the Clean Air Act," Energy & Mineral Law Foundation, Kentucky Mineral Law Conference, Lexington, KY (October 2014)

"Regulation of CO_2 Emissions from Existing Power Plants: The Clean Power Plan and Considerations for West Virginia," Monongahela Group of the Sierra Club and the WVU Sierra Student Coalition, Morgantown, WV (July 2014)

"What's Coming Down the Tracks for Midstream Operators in 2014? Emerging Issues and Regulatory Update for Crude Oil by Rail," Energy & Mineral Law Foundation 35th Annual Institute, White Sulphur Springs, WV (June 2014)

"Getting to Utility 2.0: The Evolution of the Energy Market Regulatory Paradigm to Accommodate the Customer-Centric Utility of the Future," Albany Law School Government Law Center and New York State Department of Public Service Symposium "An Energy Agenda for the Future," Albany, NY (May 2014)

"Climate Change Adaptation and Electric Utility Planning: The Resiliency Benefits of Distributed Generation and Lessons from Superstorm Sandy," Ohio Legal Scholarship Workshop, Akron, OH (February 2014)

"Starting from Scratch: Promoting Energy Efficiency Without the Foundations of IRP or an EERS," American Council for an Energy-Efficient Economy (ACEEE) National Conference on Energy Efficiency as a Resource, Nashville, TN (September 2013)

"Who Has the Power? Panel Discussion/Forum on Electric Utilities in West Virginia," Wheeling Academy of Law and Science, Wheeling, WV (September 2013)

"Workshop on the Development of Unconventional Hydrocarbons in the Appalachian Basin," National Research Council, invited participant, West Virginia University, Morgantown, WV (September 2013)

"Coal and Biomass Opportunities: Energy Policies and Environmental Impacts," Conference on Coal and Biomass Opportunities, Appalachian Hardwood Center and National Research Center for Coal and Energy at West Virginia University (September 2012)

"Energy Trends in West Virginia," West Virginia Land and Mineral Owners Association Annual Meeting (May 2012)

"Integration of Environmental Issues in Electric Utility Regulatory Proceedings," Washington & Lee College of Law Energy Symposium (February 2012)

"Adaptation Strategies: Responding to Climate Change as the New 'Normal'," Annual Meeting of Association of American Law Schools (January 2012)

"The Future of Energy: A Discussion of Alternative Energy and New Technology," conference on Environmental Sustainability presented by The Sisters of the Divine Compassion, "Going Green: Moral Imperative and Balancing Act" (May 2011)

"Get Empowered: Renewable Energy Now! A Panel Discussion on Post-Fossil Fuel Energy Solutions that Preserve New York's Natural Resources," Westchester for Change (April 2011)

"The Role of Renewable Energy in the US in the 21st Century," Westchester Community College 2011 Domestic Policy Series (April 2011)

"The Fracking Equation: Natural Gas Extraction plus Clean Water," 16th Annual Tulane Law School Summit on Environmental Law and Policy: The Energy Equation (April 2011)

"Hydrofracking: The Explosive Issue of Natural Gas Drilling," Pace Law School Center for Environmental Legal Studies (April 2011)

"Future of Energy," Bedford 2020 Environmental Action Day, Bedford, NY (January 2011)

"Transforming New York's Energy System," Cornell University, ILR School, Global Labor Institute Conference on "Perspectives on the Future of Climate Protection and Economic Development in New York State," New York City (November 2010)

"Legal and Constitutional Foundation for Addressing Climate Change Issues," Constitution Day Keynote Address, Dutchess Community College (September 2010)

"Update on Policy Development at the National Level," Sixth Annual Conference on Renewable Energy in the Pacific Northwest, Law Seminars International, Seattle, Washington (August 2010)

"Indian Point: Reliability, Economic and Environmental Considerations," New York Association for Energy Economics (July 2010)

"New York's Roadmap for Reducing Greenhouse Gases in the Transportation Sector," Second Annual Biofuels Law and Regulation Conference, University of Illinois College of Law (April 2010)

James M. Van Nostrand (continued)

"Implications of a Federal RPS: Will It Supplement or Supplant the Existing State Initiatives?" Climate Change and the Future of Energy, University of Toledo College of Law (March 2010)

"Legal Issues in Financing Energy Efficiency," Next Generation Energy and the Law, The George Washington University Law School (February 2010)

"Understanding Energy in 2010: RECs, CERES, and Beyond," American Law Institute/American Bar Association, co-sponsored by the Environmental Law Institute, ALI-ABA Teleseminar/Audio Webcast (December 2009)

"The Impact of the Recession and Stimulus Package on Renewable Energy Development," Fifth Annual Conference on Renewable Energy in the Pacific Northwest, Law Seminars International, Seattle, Washington (August 2009)

"Who Will Pay: The Impact of the ACES Act on Utility Rates," ABA Annual Meeting, Section of Real Property, Trust and Estate Law, "Greenhouse Gas Emissions: Who Will Regulate, How Will It Be Done, and Who Will Pay?" Chicago, IL (July 2009)

"Northeast Regional Greenhouse Gas Initiative (RGGI) and Carbon Trading," New Jersey Association of Energy Engineers 2009 Energy Futures Forum, Union, NJ (May 2009)

"Capturing the Value of Distributed Generation for More Effective Policymaking," American Solar Energy Society, SOLAR 2009, Buffalo, NY (May 2009)

"Federal Smart Grid Initiatives," Pace Environmental Law Society Earth Week Panel: "The Smart Grid: The Legal and Logistical Impediments of Upgrading our Nation's Electricity Grid," White Plains, NY (April 2009)

"Global Warming Today: A Hot Topic in a Cold Economic Climate," ABA Section of International Law Annual Meeting, Washington, DC (April 2009)

"Small Cogen: CHP for Individual Buildings in New York City," New York Chapter of U.S. Green Building Council (January 2009)

"Nuclear Relicensing Issues: Where Do We Get the Power and at What Price?" Pace Environmental Law Review Nuclear Relicensing Symposium (October 2008)

"Emerging International Issues in Confronting Climate Change: Adaptation and Allowance Trading," American Branch of the International Law Association, International Law Weekend 2008 (October 2008)

"Distributed Energy and the Supply Side of Electricity," EPA Workshop on Energy and Environmental Sustainability in a Carbon-Constrained Society (September 2008)

"(Pipe)line Dreams: Solving the Puzzle of Energy Independence," New York Law School's "Justice Speaks" Series (September 2008)

"Update on Renewable Portfolio Standards, Tax Incentives, Other Policy Developments," Fourth Annual Conference on Renewable Energy in the Pacific Northwest, Law Seminars International, Seattle, Washington (August 2008)

"The 'Greening' of Energy Policies Through Renewable Portfolio Standards," Climate Change & Human Rights Symposium, University of Iowa College of Law (February 2008)

"The 'Greening' of America's Energy Policy," All-Campus Lecture Sponsored by the Clayton Center for Entrepreneurial Law, University of Tennessee College of Law (September 2007)

"State Regulation After the Repeal of PUHCA," Energy Bar Association Annual Meeting, Washington, D.C. (April 2006)

Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-2, Sub 1219

April 13, 2020

Exhibit JMV-TF-2

BACKGROUND AND QUALIFICATIONS

TYLER FITCH

Q. Please state your name, title, and employer.

A. My name is Tyler Fitch. I am Southeast Regulatory Manager for Vote Solar.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Please state your educational and professional experience.

A. I began work at Vote Solar in August 2018, where I conduct economic and regulatory policy research and provide expert testimony in a variety of legislative and regulatory venues nationally and across the Southeast. My analytical work has supported Vote Solar's regulatory interventions in Virginia, South Carolina, Georgia, Florida, New Orleans, Arizona, and Michigan, including work with former Vote Solar Regulatory Director Caroline Golin on grid modernization issues in the Southeast.

Prior to my work at Vote Solar, I was a Peter & Carolyn Mertz Fellow at the University of Michigan's School for Environment and Sustainability under Rosina Bierbaum, an internationally recognized leader in climate change adaptation policy and implementation. My published works include a novel community solar business model for a non-profit in Highland Park, Michigan, a review of the distribution of resilient energy infrastructure across ratepayers, and a techno-economic model of a microgrid in Beni, Democratic Republic of Congo. I received my Master's of Science from the School in May 2018.

I worked as a consultant at ICF International from 2013 to 2016, eventually serving as the technical lead for the Better Buildings Challenge's Multifamily Sector, where I oversaw energy benchmarking and wrote the program's data policy. I also hold a Bachelor of Science in Environmental Science from the University of North Carolina at Chapel Hill. My professional background is described in detail in my *curriculum vitae*, attached hereto.

Q. Have you previously testified before the North Carolina Utilities Commission ("the Commission")?

A. No.

Tyler J. Fitch

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EDUCATION

Master's of Science in Natural Resources, focus in Energy Policy. *School for the Environment and Sustainability, University of Michigan,* 2018.
Bachelor's of Science in Environmental Sciences. *University of North Carolina at Chapel Hill*, 2013.

PROFESSIONAL EXPERIENCE & RELEVANT WORK

Vote Solar. **Regulatory Manager, Southeast.** *August 2018 – Present.* Support Vote Solar's regulatory and legislative work through quantitative analysis and policy research, and expert testimony. Contributed analysis and testimony for regulatory intervention in Virginia, North Carolina, South Carolina, Georgia, Florida, New Orleans, Arizona, and Michigan since August 2018.

Environmental Defense Fund. **Climate Corps Fellow.** May – August 2017 & 2018. Quantitative analysis and comment drafting on behalf of Environmental Defense Fund and Citizens Utility Board to Illinois Power Agency's Request for Comments on the Long-Term Renewable Resources Procurement Plan (LTRRPP). Led program development on Environmental Defense Fund and the Accelerate Group's *SolarInTheCommunity.com* platform.

Southern California Edison. **Graduate Consultant.** *August – December 2016.* Assisted in market valuation study for electrification in SCE service territory.

ICF International. **Research Analyst.** *October 2013 – June 2016*. Technical & quantitative analysis for federal, state, and local energy efficiency programs. Served as Multifamily Technical Lead for the Department of Energy Better Buildings Challenge, 2015-2016. Provided quantitative support for President Barack Obama's 2015 Remarks on the Better Buildings Challenge. Led policy design and implementation for the City of Cambridge, MA's Building Energy Use Disclosure Ordinance (BEUDO).

REGULATORY & RULEMAKING PARTICIPATION

- ***Expert Testimony.*** North Carolina Utilities Commission, Docket # E-7, Sub 1214. Duke Energy Carolinas Rate Case. February 2020.
- ***Expert Testimony.*** Georgia Public Service Commission, Docket #42516. Georgia Power Rate case. December 2019.
- ***Comments Submitted.*** North Carolina Department of Environmental Quality. Submitted comments on Draft Clean Energy Plan. September 2019.

- ***Supporting Analysis.*** Florida Public Service Commission 20190061-EI. FPL SolarTogether Proposal. Supporting analysis for testimony of William M. Cox. September 2019.
- ***Comments Submitted.*** City of New Orleans Docket No. UD-19-01. Proceeding to Establish Renewable Portfolio Standards. Submitted comments June 2019.
- ***Supporting Analysis.*** Arizona Corporation Commission Docket No. RU-00000A-18-0284. Modifications to the Commission's Energy Rules. Supporting analysis for Joint Stakeholder Proposal for New Energy Rules. June 2019.
- ***Supporting Analysis.*** Georgia Public Service Commission Docket 42310 &42311. Georgia Power Company's 2019 Integrated Resource Plan. Supporting analysis for testimony of William M. Cox. April 2019.
- ***Supporting Analysis.*** Florida Public Service Commission 20180204-EI. TECO Shared Solar Tariff. Supporting analysis and drafting for Vote Solar's Comments. April 2019.
- ***Supporting Analysis.*** South Carolina Public Service Commission No. 2018-318/9-E. Duke Energy Progress/Carolinas Rate Cases. Supporting analysis for testimony of Justin Barnes. March 2019.
- ***Supporting Analysis.*** Michigan Public Service Commission Case No. U-20162. DTE Energy Rate Case. Supporting analysis for testimony of Will Kenworthy. November 2018.
- ***Supporting Analysis.*** Virginia Electric and Power Company Case No. PUR-2018-00100. Supporting analysis for testimony of Caroline Golin. October 2018.

PUBLICATIONS

- Fitch, T. "Understanding Electric Utility Ratemaking, Rate Design, and the Value of Clean Energy." Presentation given at Southface Energy Institute, February 2019.
- Fitch, T. (2018, April) Islands of Light: Microgrids and the Public Good. *Agora Planning Journal,* 12, 74-80.
- Vanderwilde, C., Fitch, T., Mueller, E., (2018, April). Fueling a Transition: Evaluating the Feasibility of a Hybrid Renewable Microgrid in Beni, Democratic Republic of Congo, manuscript. University of Michigan School for the Environment and Sustainability.
- Fitch, T., Lenhart, A., Buchanan, C., Jeong, B. (2018, January). Get Free: Understanding the Potential for Community Solar Power in Highland Park. Dow Sustainability Fellow Report Series.
- Fitch, T., (2017, September). "How Illinois is working toward a cleaner, more equitable energy future." EDF Energy Exchange.
- Fitch, T., (2016, December). "Closing the Adoption Gap: Affordable Solar Power and Energy Justice." University of Michigan School of Natural Resources & Environment Policy Brief Series.

HONORS / AWARDS

Clean Energy Leadership Institute Fellow, 2019
Peter & Carolyn Mertz Fellow, 2018
UNLEASH Lab Climate Action Runner-up, 2018
Presenter at Sustainable Energy Transitions Initiative, 2018
University of Michigan Delegate to UNFCCC COP 23, 2017
Environmental Defense Fund Climate Corps Advocacy Fellow, 2017
Dow Sustainability Fellow, 2017
University of Michigan Academic Leadership Fellow, 2016
ICF International Project of the Year, 2016

Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-2, Sub 1219

April 13, 2020

Exhibit JMV-TF-3

I/A

North Carolina
Climate Science Report

Report Findings and Executive Summary

NCICS

North Carolina
Climate Science Report

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March 2020

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Subject to final copyedit and layout.

Foreword

The North Carolina Climate Science Report is a scientific assessment of historical climate trends and potential future climate change in North Carolina under increased greenhouse gas concentrations. It supports Governor Cooper's Executive Order 80 (EO80), "North Carolina's Commitment to Address Climate Change and Transition to a Clean Energy Economy," by providing an independent peer-reviewed scientific contribution to the EO80.

The report was prepared independently by North Carolina-based climate experts informed by (i) the scientific consensus on climate change represented in the Fourth United States National Climate Assessment and the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, (ii) the latest research published in credible scientific journals, and (iii) information in the North Carolina State Climate Summary.

An advisory panel ("Climate Science Advisory Panel") was formed to provide oversight and review of the report. This panel consisted of North Carolina university and federal research scientists with national and international reputations in their specialty areas of climate science.

The report underwent several rounds of review and revision, including an anonymous peer review organized by NOAA's National Centers for Environmental Information (NCEI). The report is available via: ncics.org/nccsr.

Report Findings

These findings present key conclusions of this report about observed and projected changes in the climate of the state of North Carolina.

Quantitative projections for temperature, precipitation, and sea level rise are provided for two future scenarios: a higher scenario (RCP8.5), in which greenhouse gas emissions continue to increase through the end of this century, and a lower scenario (RCP4.5), in which emissions increase at a slower rate, peak around the middle of this century, and then begin to decrease. Future increases in temperature are dependent on greenhouse gas emissions, with higher emissions resulting in greater warming. Qualitative projections are based on expert judgment and assessment of the relevant scientific literature and draw on multiple lines of scientific evidence as well as model simulations.

Global average temperature has increased about 1.8°F since 1895. Scientists have ***very high confidence*** that this warming is largely due to human activities that have significantly increased atmospheric concentrations of carbon dioxide (CO_2) and other greenhouse gases. It is ***virtually certain*** that global warming will continue, assuming greenhouse gas concentrations continue to increase. By the end of this century (2080–2099), global average temperature is projected to increase by about 4°–8°F compared to the recent climate (1996–2015) under the higher scenario (RCP8.5) and by about 1°–4°F under the lower scenario (RCP4.5).

Global average sea level has increased by about 7–8 inches since 1900, with almost half of this increase occurring since 1993. It is ***virtually certain*** that global sea level will continue to rise due to expansion of ocean water from warming and melting of ice on land, such as the Greenland and Antarctic ice sheets.

Observed and Projected Changes for North Carolina

Except where noted, statements about future changes refer to projections through the end of this century.

- Our scientific understanding of the climate system strongly supports the conclusion that large changes in North Carolina's climate, much larger than at any time in the state's history, are ***very likely*** by the end of this century under both the lower and higher scenarios.

Temperature

- North Carolina annual average temperature has increased by about 1.0°F since 1895, somewhat less than the global average. The most recent 10 years (2009–2018), however, represent the warmest 10-year period on record in North Carolina, averaging about 0.6°F warmer than the warmest decade in the 20th century (1930–1939). Recently released data indicate that 2019 was the warmest year on record for North Carolina.

- Although regional changes in temperature can vary from global changes, it is ***very likely*** that North Carolina temperatures will also increase substantially in all seasons. Annual average temperature increases relative to the recent climate (1996–2015) for North Carolina are projected to be on the order of 2°–5°F under a higher scenario (RCP8.5) and 2°–4°F under a lower scenario (RCP4.5) by the middle of this century. By the end of this century, annual average temperature increases relative to the recent climate (1996–2015) for North Carolina are projected to be on the order of 6°–10°F under a higher scenario (RCP8.5) and 2°–6°F under a lower scenario (RCP4.5).
- North Carolina has not experienced an increase in the number of hot (daytime maximum temperatures above 90°F) and very hot (daytime maximum temperatures above 90°F) summer days since 1900. However, it has seen an increase in the number of warm (nighttime minimum temperatures above 70°F) and very warm nights (nighttime minimum temperatures above 75°F).
- It is ***very likely*** that the number of warm and very warm nights will increase.
- It is ***very likely*** that summer heat index values will increase because of increases in absolute humidity.
- It is ***likely*** that the number of hot and very hot days will increase.
- It is ***likely*** that the number of cold days (daytime maximum temperatures below 32°F) will decrease.

Precipitation

- There is no long-term trend in annual total precipitation averaged across the state. However, there is an upward trend in the number of heavy rainfall events (3 inches or more in a day), with the last four years (2015–2018) having seen the greatest number of events since 1900.
- It is ***likely*** that annual total precipitation for North Carolina will increase.
- It is ***very likely*** that extreme precipitation frequency and intensity in North Carolina will increase due to increases in atmospheric water vapor content.

Sea Level

- Sea level along the northeastern coast of North Carolina has risen about twice as fast as along the southeastern coast, averaging 1.8 inches per decade since 1978 at Duck, NC, and 0.9 inches per decade since 1935 at Wilmington, NC.
- It is ***virtually certain*** that sea level along the North Carolina coast will continue to rise due to expansion of ocean water from warming and melting of ice on land, such as the Greenland and Antarctic ice sheets. Under a higher scenario (RCP8.5), storm-driven

water levels that have a 1% chance of occurring each year in the beginning of the 21st century may have as much as a 30%–100% chance of occurring each year in the latter part of the century. High tide flooding, defined as water levels of 1.6–2.1 feet (0.5–0.65 meters) above Mean Higher High Water, is projected to become a nearly daily occurrence by 2100 under both the lower and higher scenarios.

Hurricanes

- The intensity of the strongest hurricanes is ***likely*** to increase with warming, and this could result in stronger hurricanes impacting North Carolina. Confidence in this result is ***high*** for global hurricane changes but lower for individual regions such as North Carolina.
- Heavy precipitation accompanying hurricanes that pass near or over North Carolina is ***very likely*** to increase, which would in turn increase the potential for freshwater flooding in the state.
- There is ***low confidence*** concerning future changes in the number of landfalling hurricanes in North Carolina.

Storms

- It is ***likely*** that the frequency of severe thunderstorms in North Carolina will increase.
- It is ***likely*** that total snowfall and the number of heavy snowstorms in North Carolina will decrease due to increasing winter temperatures.
- There is ***low confidence*** concerning future changes in the number of winter coastal storms.
- There is ***low confidence*** concerning future changes in the number of ice storms in North Carolina.

Floods, Droughts, and Wildfire

- It is ***virtually certain*** that rising sea level and increasing intensity of coastal storms, especially hurricanes, will lead to an increase in storm surge flooding in coastal North Carolina.
- It is ***likely*** that increases in extreme precipitation will lead to increases in inland flooding in North Carolina.
- It is ***likely*** that future severe droughts in North Carolina will be more intense due to higher temperatures leading to increased evaporation. As a result, it is ***likely*** that the frequency of climate conditions conducive to wildfires in North Carolina will increase.

Other Compound Events

- It is ***likely*** that future urban growth will increase the magnitude of the urban heat island effect, with stronger warming in North Carolina urban centers.
- There is ***low confidence*** concerning future changes in conditions favorable for near-surface ozone formation in North Carolina because of counteracting influences from increases in both temperature and water vapor.

Engineering Design Standards

- It is ***very likely*** that some current climate design standards for North Carolina buildings and other infrastructure will change by the middle of the 21st century. This includes increases in design values for precipitation, temperature, and humidity. Several professional societies, however, are actively working on methods to incorporate climate change into national standards, and updated standards appropriate for use in a changing climate may be available in the near future.

Executive Summary

Our scientific understanding of the climate system strongly supports the conclusion that North Carolina's climate has changed in recent decades and the expectation that large changes—much larger than at any time in the state's history—will occur if current trends in greenhouse gas concentrations continue. Even under a scenario where emissions peak around 2050 and decline thereafter, North Carolina will experience substantial changes in climate. The projected changes with the highest level of scientific confidence include increases in temperature, increases in summer absolute humidity, increases in sea level, and increases in extreme precipitation. It is also ***likely*** that there will be increases in the intensity of the strongest hurricanes.

A full appreciation for past and future changes in North Carolina's climate requires a global perspective. Earth's climate has warmed substantially since the late 19th century, with most of that warming occurring in the last 50 years. This warming trend is clear from global temperature records and many other indicators, including rising global sea levels and rapid decreases in arctic sea ice cover. Scientists have ***very high confidence*** that this warming is largely due to human activities that have significantly increased atmospheric concentrations of carbon dioxide (CO_2) and other greenhouse gases. Extensive research has examined other potential causes of this warming, and the increase in greenhouse gas concentrations is the only plausible cause that is consistent with the observed data and the physics that govern the climate system.

Observed Changes

In North Carolina, annual average temperature has increased about 1°F since 1895, compared to the global average increase of about 1.8°F during that period. Annual average temperatures have been consistently above normal since the 1990s, with the most recent 10 years (2009–2018) representing the warmest 10-year period on record—about 0.6°F warmer than the warmest decade of the 1900s (1930–1939). Data for 2019, which were released during the review of this report, indicate that 2019 was the warmest year on record for North Carolina.

Most other temperature indicators also show warming. Average temperatures have increased in all four seasons. There has been an increase in the number of very warm nights. The length of the growing season has increased and is now about 1.5 weeks longer than the long-term average. There is an upward trend in the number of cooling degree days (a temperature indicator related to air conditioning demand) and a downward trend in the number of heating degree days (an indicator of heating demand)—both changes are consistent with a warming climate. However, a few indicators that would be expected to change with warmer conditions have not. For example, the number of very hot days has not increased, and there is no overall trend in the number of cold days and cold nights.

There is no long-term trend in annual total precipitation averaged across the state; however, 2018 was the wettest year on record, in part due to the torrential rainfall from Hurricane Florence. There has been an upward trend in the number of heavy rainfall events (days with more than 3 inches of rain), indicating that a larger portion of the annual total precipitation is occurring in heavy events. Temperature and precipitation trends in the three regions of the state (Coastal Plain, Piedmont, and Western Mountains) are generally similar to statewide trends.

Most observing stations outside of the mountains have experienced a downward trend in snowfall. In the Western Mountains, there is no century-long trend in snowfall, although stations in the southern mountains have seen decreasing trends over the last 50 years. Conditions favorable for snow-cover maintenance and snowmaking in the Western Mountains have been highly variable since 1981, but recent years have seen below average percentages of time when conditions are favorable.

Global average sea level has increased by about 7–8 inches since 1900, with almost half of this increase occurring since 1993—a rate of about 1.2 inches per decade. Sea level along the northeastern coast of North Carolina is rising about twice as fast as along the southeastern coast, averaging 1.8 inches per decade since 1978 at Duck, NC, and 0.9 inches per decade at Wilmington, NC, mainly due to different rates of land subsidence.

Projected Changes

The projections of North Carolina climate conditions presented in this report are based on the ***virtual certainty*** that greenhouse gas concentrations, particularly CO_2, will continue to rise. It may take decades for non-carbon-based sources of energy to replace most of the production based on fossil fuels. The basic principles of physics dictate that increases in greenhouse gas concentrations will have a warming effect, with ***virtual certainty***, due to the increase in atmospheric absorption of infrared energy.

Quantitative projections for temperature, precipitation, and sea level rise are provided for two future scenarios: a higher scenario (RCP8.5), in which greenhouse gas emissions continue to increase through the end of this century, and a lower scenario (RCP4.5), in which emissions increase at a slower rate, peak around the middle of this century, and then begin to decrease. RCP8.5 and RCP4.5 are Representative Concentration Pathways—scenarios used in climate model simulations to examine how Earth's climate would respond to differing levels of greenhouse gas concentrations. The numbers 8.5 and 4.5 refer to the magnitude of the energy imbalance in the climate system (in units of watts per square meter) that would result in the year 2100 from the increases in greenhouse gas concentrations specified by the respective scenarios. By comparison, the increase in concentrations since the initiation of the Industrial Revolution has resulted in an imbalance of approximately 2.3 watts per square meter.

A very low scenario (RCP2.6) is also used occasionally in this report, but this scenario is very unlikely because there has been no slowdown in the annual growth rate of CO_2. Qualitative projections are based on expert judgment and assessment of the relevant scientific literature and draw on multiple lines of scientific evidence as well as model simulations. Except where noted, statements below about future changes refer to projections through the end of this century.

By the end of this century (2080–2099), global average temperature is projected to increase by about 4°–8°F compared to the current climate (1996–2015) under the higher scenario (RCP8.5) and by about 1°–4°F under the lower scenario (RCP4.5). The warming is projected to be greater in the middle and high latitudes and less at tropical latitudes.

Regional changes in temperature can differ from global changes, at least temporarily, as shown by the historical lower rate of warming in North Carolina compared to the global average. Seasonal and annual average temperatures, however, have been rising in North Carolina in recent decades, and it is ***very likely*** that North Carolina temperatures will continue to increase substantially in all seasons.

- By the middle of this century, annual average temperature increases relative to the current climate (1996–2015) for North Carolina are projected to be on the order of 2°–5°F under the higher scenario (RCP8.5) and 2°–4°F under the lower scenario (RCP4.5).
- By the end of this century, annual average temperature increases relative to the current climate (1996–2015) for North Carolina are projected to be on the order of 6°–10°F under the higher scenario (RCP8.5) and 2°–6°F under the lower scenario (RCP4.5).

Temperature extremes are also projected to change:

- It is ***very likely*** that the number of very warm nights will increase, continuing recent trends.
- It is ***likely*** that the number of very hot days will increase, although the level of confidence is lower than for very warm nights because of the lack of recent trends.
- It is ***likely*** that the number of cold days and very cold nights will decrease, but again the level of confidence is lower than for very warm nights because of the lack of recent trends.

Several additional climate features directly tied to temperature are also projected to change, with a high level of certainty:

- It is ***very likely*** that extreme precipitation frequency and intensity will increase because global ocean surface temperatures will continue to increase gradually. In turn, near-surface air temperature and absolute humidity will increase over the oceans because maximum water vapor content is strongly related to temperature, increasing by about 3.5% per °F.
- It is ***virtually certain*** that global sea level will continue to rise due to both the expansion of ocean water from warming and from the melting of ice on land, including the Greenland and Antarctic ice sheets. It is ***virtually certain*** that sea level along the North Carolina coast will also continue to rise. Under the higher scenario (RCP8.5), storm-driven water levels having a 1% chance of occurring each year in the beginning of the 21st century may have as much as a 30%–100% chance of occurring each year in the

latter part of the century. High tide flooding is projected to become nearly a daily occurrence by 2100 under both the lower and higher scenarios.

- It is ***very likely*** that summer heat index values will increase because of increases in absolute humidity.
- It is ***likely*** that the probability of snowfall and snow cover will decrease nearly everywhere in North Carolina because of warmer temperatures.

For climate variables where the temperature dependence is more complex, projected changes are less certain:

- Inland flooding depends not only on extreme precipitation but also on characteristics of the land surface, including land use, land cover, and soil moisture conditions. It also depends on whether deliberate adaptive measures are implemented proactively. It is ***likely*** that the frequency and severity of inland flooding will increase because of increases in the frequency and intensity of extreme precipitation. This lower level of certainty compared to projections for changes in extreme precipitation stems from the additional factors that determine flooding.
- It is ***likely*** that annual total precipitation in the state will increase, but there is less certainty for annual total precipitation than for projected increases in extreme precipitation, because total precipitation is a function of both atmospheric water vapor and the frequency and intensity of weather systems that cause precipitation. Future changes in the intensity and frequency of such weather systems are more uncertain.

Hurricanes have some of the most important impacts on the state, often catastrophic (storm surge, wind, and flooding damage) but sometimes beneficial (rainfall recharging soil moisture and groundwater aquifers). An understanding of future changes in hurricanes has been the subject of extensive research by climate scientists. While that understanding continues to evolve, a recent assessment of the science leads to the conclusion that the intensity of the strongest hurricanes is ***likely*** to increase with warming, and this could result in stronger hurricanes impacting North Carolina. Confidence in this result is ***high*** for tropical cyclone changes on a global scale but lower on a regional level, such as North Carolina.

It is ***virtually certain*** that rising sea level and increasing intensity of coastal storms, especially hurricanes, will lead to increases in storm surge flooding in coastal North Carolina. There is ***low confidence*** concerning future changes in the total number of hurricanes. The total number of hurricanes depends on a variety of meteorological factors, such as vertical wind shear (changes in wind speed or direction with height in the atmosphere), and not just ocean surface temperatures, and there is considerable uncertainty about changes in these other factors. Heavy precipitation accompanying hurricanes is ***very likely*** to increase, increasing the potential for freshwater floods.

Severe thunderstorms (hail, tornadoes, and strong winds) are a regular occurrence in North Carolina, particularly in the spring. Severe thunderstorms require two primary atmospheric conditions: an unstable atmosphere and high vertical wind shear. It is ***very likely*** that vertical instability will increase, but it is also ***likely*** that vertical wind shear will decrease. These may counteract one another. Recent research suggests that the increases in atmospheric instability will dominate. While this remains an active area of research, it is ***likely*** that there will be increases in the frequency of severe thunderstorms.

Other important weather systems include snowstorms, winter coastal storms, and ice storms. There is considerable uncertainty about future changes in the number and severity of extratropical cyclones—the weather phenomenon that causes each of these winter storm types. In the case of snow, temperature is an important factor, and it is ***likely*** that total snowfall and the number of heavy snowstorms will decrease because of increasing temperatures. There is ***low confidence*** concerning future changes in the number of ice storms and winter coastal storms.

Drought can have major impacts on the state, including agricultural production and wildfires. It is ***likely*** that major droughts will become more severe because of higher temperatures that will increase evaporation rates. As a result, it is ***likely*** that the climate conditions conducive to wildfires in North Carolina will increase in the future.

The major urban areas of the state have expanded substantially over the past few decades, and this trend shows no signs of abating. The urban heat island effect results from the conversion of vegetated surfaces (such as forests and farmland) to urban and suburban landscapes with substantial percentages of impervious, non-vegetated surfaces, reducing the amount of natural cooling from evapotranspiration (the combination of evaporation of water from the surface and transpiration of water vapor from vegetation) and increasing the amount of heat retained in darker, paved surfaces as compared to natural land cover. It is ***likely*** that future warming in urban areas will be enhanced by future growth of those areas.

Near-surface ozone is a major component of air pollution, and harmful levels of near-surface ozone result from a combination of climate conditions and human-caused emissions of compounds necessary for the formation of ozone, including nitrogen oxides, carbon monoxide, and volatile organic compounds (referred to as ozone precursor compounds). Near-surface ozone concentrations tend to increase with temperature. However, changes in other climate conditions, such as increased precipitation, can counteract the temperature effect. Overall, it is uncertain what the net effect will be. Thus, there is ***low confidence*** concerning future changes in the conditions favorable for near-surface ozone concentrations.

Climate design values, which provide information on the average and extreme climate conditions experienced in a given location, are important for planning and designing many types of infrastructure. Many climate design values are projected to change because of warming. Because of the high level of confidence in increased temperature and extreme precipitation, it is ***very likely*** that some current climate design standards for building and other infrastructure will change by the middle of this century. This includes increases in design values for precipitation, temperature, and humidity. In fact, current design values are based on historical data and do not incorporate recent trends; thus, some standards may already be out of date. Several professional societies, however, are actively working on methods to incorporate climate change into national standards, and updated standards appropriate for use in a changing climate may be available in the near future.

Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-2, Sub 1219

April 13, 2020

Exhibit JMV-TF-4

I/A

Climate Change Vulnerability Study

December 2019

Climate Change Vulnerability Study

December 2019

In partnership with:

Lamont-Doherty Earth Observatory
COLUMBIA UNIVERSITY | EARTH INSTITUTE

With contributions from O'Neill Management Consulting, LLC, The Risk Research Group, Inc., and Jupiter Intelligence Inc.

Table of Contents

Executive Summary

In its 2013 rate case filing after Superstorm Sandy, Con Edison proposed $1 billion in storm hardening investments to build additional resiliency into its energy systems. Con Edison worked with a Storm Hardening and Resiliency Collaborative to recommend optimal investments for the proposed storm hardening funds, including the recommendation that Con Edison conduct a Climate Change Vulnerability Study (Study). As described by the New York State Public Service Commission, the purpose of this Study is to aid in the ongoing review of the Company's design standards and development of a risk mitigation plan.[1] Over the course of the Study, Con Edison regularly convened a stakeholder group to provide feedback, consisting of many of the same participants from the Storm Hardening and Resiliency Collaborative. The findings from the Study equip Con Edison with a better understanding of future climate change risks and strengthen the company's ability to more proactively address those risks.

This Study describes historical and projected climate changes across Con Edison's service territory, drawing on the best available science, including downscaled climate models, recent literature, and expert elicitation. Con Edison recognizes the global scientific consensus that climate change is occurring at an accelerating rate. The exact timing and magnitude of future climate change is uncertain. To account for climate uncertainty, the Study considered a range of potential climate futures reflecting both unabated and reduced greenhouse gas concentrations through time and evaluated extreme event "stress test" scenarios.

This Study evaluates present-day infrastructure, design specifications, and procedures against expected climate changes to better understand Con Edison's vulnerability to climate-driven risks. This analysis identified sea level rise, coastal storm surge, inland flooding from intense rainfall, hurricane-strength winds, and extreme heat as the most significant climate-driven risks to Con Edison's systems. Con Edison has unique energy systems, and vulnerabilities vary across those systems. The utility's electric, gas, and steam systems are all vulnerable to increased flooding and coastal storms; workers across all commodities are vulnerable to increasing temperatures; and the electric system is also vulnerable to heat events.

While Con Edison already uses a range of measures to build resilience to weather events, the vulnerabilities identified in this Study guide the company to pursue additional strategies to mitigate climate risks. The Study establishes an overarching framework that can work to strengthen Con Edison's resilience over time. While many adaptation strategies focus on avoiding impacts altogether, a comprehensive resilience plan also requires a system that can reduce and recover from impacts, particularly following outages.

Over the course of 2020, Con Edison will develop and file a Climate Change Implementation Plan, which will specify a governance structure and a strategy for implementing adaptation options over the next 5, 10, and 20 years. While this Study assesses vulnerabilities within Con Edison's present-day systems to a future climate, the implementation plan must also consider the evolving market for energy services, and potential changes to services and infrastructure driven by customers, government policy and external actions over time.

[1] Cases 13-E-0030, 13-G-0031, 13-S-0032, Order Adopting Storm Hardening and Resiliency Collaborative Phase Three Report Subject to Modifications (January 25, 2016).

The Need for a Study

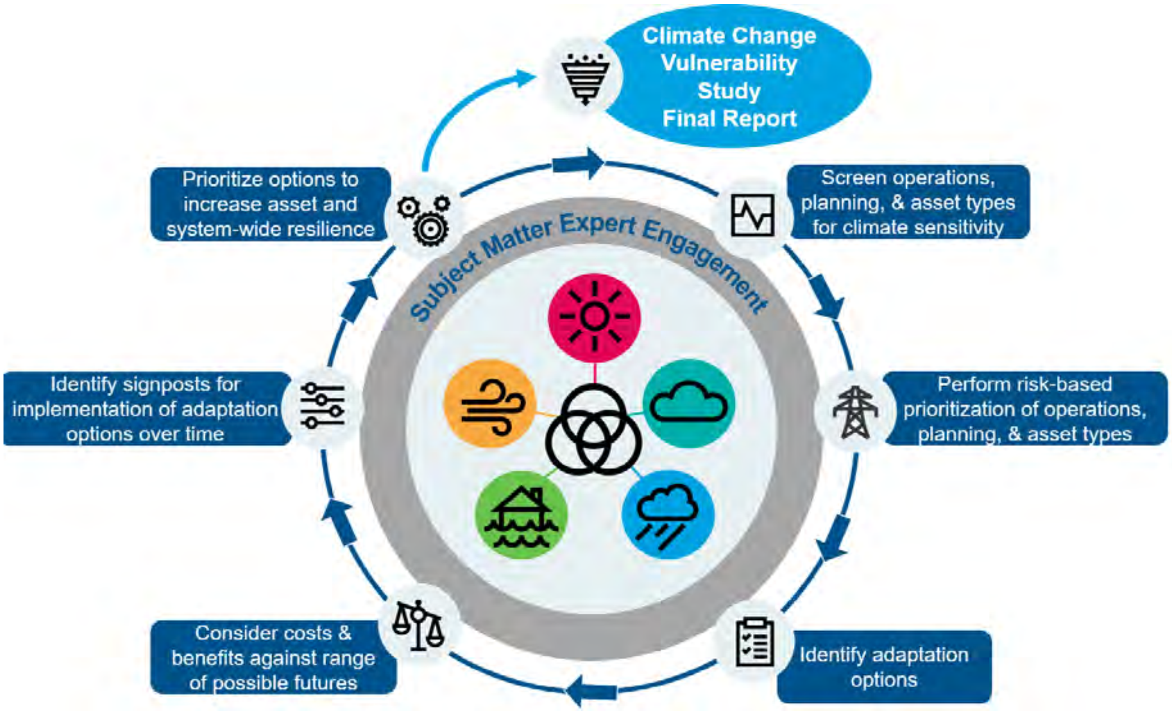
The New York State Public Service Commission approved an Order and funding for Con Edison to conduct a Climate Change Vulnerability Study, with a requirement for delivery by the end of 2019. The Con Edison Department of Strategic Planning undertook this Study with support from more than 100 subject matter experts throughout the company and in collaboration with ICF's climate adaptation and resilience experts and Columbia University's Lamont-Doherty Earth Observatory. The Study was designed to meet three primary goals:

Con Edison's resilience to climate change has important implications for increasingly interconnected societal, technological, and financial systems that the company serves.

1. Research and develop a shared understanding of new climate science and projected extreme weather for the service territory.
2. Assess the risks of potential impacts of climate change on operations, planning, and physical assets.
3. Review a portfolio of operational, planning, and design measures, considering costs and benefits, to improve resilience to climate change.

The Study used an integrated approach to achieve these goals, as shown in Figure 1.

Figure 1 General approach overview: The process cycles through the steps for each climate hazard, beginning with 'Screen operations, planning, and asset types for climate sensitivity'. The process results in the Climate Change Vulnerability Study Final Report.



A New Understanding of Climate Science and Extreme Weather

Con Edison will face new challenges from a rapidly changing climate through the 21st century. To better understand these challenges, the Study characterized historical and projected changes to climate hazards within the service territory to estimate the magnitude and timing of potential climate vulnerabilities. Climate variables that present outsized impacts to Con Edison include temperature, humidity, precipitation, sea level rise, and extreme events, such as rare hurricanes and long-duration heat waves.

Temperature

Average and maximum air temperatures are projected to increase throughout the century relative to historical conditions. Assuming unabated greenhouse gas concentrations, Con Edison could experience up to 23 days per year in which maximum temperatures exceed 95°F by 2050 relative to 4 days historically. Heat waves with 3 or more days when *average* temperatures exceed 86°F in Central Park are projected to occur up to 5 and 14 times per year by 2050 and 2080, respectively, relative to 1 heat wave every 5 years historically.

Humidity

The frequency of very high heat index thresholds, which combines both temperature and humidity, is projected to increase dramatically through the century. The number of days per year where the heat index equals or exceeds 103°F could increase by 7 to 26 days by 2050, compared with only 2 days historically. In addition, Con Edison evaluates the relationship of system load to an index called temperature variable (TV), which is similar to a heat index, but considers the persistence of heat and humidity over several days. Looking forward, TV thresholds that historically occur only once per year (e.g., 86°F) are projected to become common occurrences within a generation, occurring between 4 and 19 times per year by 2050 and between 5 and 52 times per year by 2080 based on reduced and unabated greenhouse gas concentrations, respectively.

Precipitation

Con Edison's service territory experiences rainfall, downpours, snowfall, and ice. Climate change is projected to drive heavier precipitation across these event types. For example, the heaviest 5-day precipitation total could be 11.8 inches at Central Park by 2050, which represents a 17% increase over the historical reference period. Ultimately, projections point to a future defined by more frequent heavy precipitation, likely accompanied by smaller increases in the frequency of dry or light precipitation days.

Sea Level Rise

Sea levels are very likely to rise between 0.62 and 1.94 feet by 2050. In turn, rising sea levels will have profound effects on coastal flooding, as sea level rise increases both the frequency and height of future floods. For example, the flood height associated with the 1% annual chance flood (i.e., the so-called 100-year flood) in New York City is projected to increase from 8.3 feet to as much as 13.3 feet by 2100 relative to mean sea level at the Battery tide gauge. By the end of the century, today's annual chance flood could occur at every high tide.

Extreme Events

Extreme events are low-probability and high-impact phenomena, such as hurricanes and long-duration heat waves. While difficult to simulate in climate models, a growing body of evidence suggests that many extreme events will increase in frequency and intensity as a result of climate warming. This Study considers high impact "worst-case"[2] extreme event scenarios, including a prolonged heat wave, a Category 4 hurricane, and an unprecedented nor'easter, to understand these changes and their impacts on Con Edison.

Characterization of Con Edison's Vulnerabilities to Climate Risks

Heat and Temperature Variable

The core electric vulnerabilities to increasing temperature and TV include increased asset deterioration, decreased system capacity, increased load, and decreased system reliability. Since the internal temperature of electric power equipment is determined by the ambient temperature as well as the power being delivered, higher ambient temperatures increase the internal operating temperature of equipment.

Higher internal operating temperatures increase the rate of aging of the insulation of electric equipment such as transformers, resulting in decreased total life of the assets. Higher internal temperatures, resulting from higher average and maximum ambient temperatures, also reduce the delivery capacity of electric equipment such as transformers. In addition, higher ambient temperatures increase the operating temperature of overhead transmission lines, causing increased sagging. One remedy is to decrease the operational rating of the assets to reflect the new operating environment. However, derating the system due to increasing temperatures would effectively decrease the capacity of the system, and Con Edison will need to make investments to replace that capacity if it is needed.

Similarly, higher TV can cause higher peak loads due to increases in demand for cooling. Increases in load may also require investments in system capacity to meet the higher demand. The combination of decreased capacity and increased load is best addressed through Con Edison's existing 10- and 20-year load relief program. Addressing this combined risk is estimated to cost between $1.3 billion and $4.6 billion by 2050 (based on future projections using Representative Concentration Pathway (RCP) 4.5 10th and RCP 8.5 90th percentiles, respectively).

Increases in heat waves are expected to affect the electric network and non-network systems by decreasing reliability. Con Edison uses a Network Reliability Index (NRI) model to determine the reliability of the underground distribution networks. The Study's forward-looking NRI analysis found that with an increase in the frequency and duration of heat waves by mid-century, between 11 and 28 of the 65 underground networks may not be able to maintain Con Edison's standard of reliability by 2050, absent adaptation.

Outdoor worker safety may be a concern across all Con Edison commodities if heat index values rise as projected. When needed, Con Edison can implement safety protocols (e.g., shift modifications and hydration breaks) already practiced in mutual aid work that the company provided in hotter locations such as Florida and Puerto Rico. Similarly, to supply sufficient cooling in 2080, Con Edison's heating, ventilation, and air conditioning (HVAC) capacity will have to increase by 11% due to projected increases in dry bulb temperature. These systems have a roughly

[2] "Worst-case" scenarios are meant to explore Con Edison system vulnerabilities related to rare extreme weather events and formulate commensurate adaptation and resilience strategies. Scenarios represent one plausible permutation of extreme weather and the severity of actual events may exceed those considered.

15-year life span and therefore can be upgraded during routine replacements with minimal cost increases.

Flooding from Precipitation, Sea Level Rise, and Coastal Storms

All underground assets are vulnerable to flooding damage (i.e., water pooling, intrusion, or inundation) from precipitation events, sea level rise, and coastal storms. Following Superstorm Sandy in 2012, Con Edison protected all infrastructure in the floodplain against future 100-year storms and 1 foot of sea level rise (e.g., submersible infrastructure, flood walls, pumps, elevation). Sea level rise projections suggest that Con Edison's 1 foot of sea level rise risk tolerance threshold may be exceeded as early as 2030 and as late as 2080.

Electric substations, overhead distribution, underground distribution, and the transmission system are sensitive to precipitation-based hazards, although the design of Con Edison's assets already mitigates some of these risks. For example, flooding from increased intense precipitation can damage non-submersible electrical equipment, although Con Edison designs all underground cables and splices to operate while submerged in water. In addition, all underground distribution equipment installed in flood zones and all new installations are submersible.

To assess future asset vulnerability to sea level rise and storm surge, the Study team analyzed the exposure of Con Edison's assets to 3 feet of sea level rise, while keeping the other elements of Con Edison's existing risk tolerance constant (i.e., a 100-year storm with 2 feet of freeboard). Of the 324 substations (encompassing generating stations, area substations, transmission stations, unit substations, and Public Utility Regulating Stations), 75 would be vulnerable to flooding during a 100-year storm if sea level rose 3 feet. In addition, 32 gas regulators and five steam generation stations would be exposed. Hardening all of these assets would cost approximately $680 million.

Both the gas and steam distribution systems are vulnerable to water entry, which can reduce system pressure and limit distribution capacity. In the gas system, low-pressure segments[3] are particularly vulnerable to this risk. In addition, the steam system is susceptible to "water hammer" events when a high volume of water collects around a manhole, causing steam in the pipes underneath to cool and condense. Interaction between steam and the built-up condensate may cause an explosion, both damaging the steam system and putting public safety at risk.

Across all commodities, increased winter precipitation can wash salt from city roads, causing an influx of salt-saturated runoff into manholes and percolation into the ground. Salt can cause equipment degradation, arcing, manhole fires or explosions, and failure of underground assets.

Extreme and Multi-Hazard Events

The Study team reviewed the vulnerabilities of Con Edison's electric, gas and steam systems to future extreme events based on specific, worst case extreme event narratives (Category 4 hurricane, a strong nor'easter, and a prolonged heat wave) designed to stress-test these systems.

Storm surge driven by an extreme hurricane event (i.e., a Category 4 hurricane) has the potential to flood both aboveground and belowground assets. In addition, wind stress and windblown debris can lead to tower and/or line failure of the overhead transmission system and damage overhead distribution infrastructure, which could cause widespread customer outages.

[3] The Con Edison gas system contains piping operating at three pressures: low, medium, and high.

An extreme nor'easter may cause significant damage to assets across all commodities. During nor'easters, accumulation of radial ice can cause tower or line failure of the overhead transmission system. Similarly, snow, ice, and wind can damage the overhead distribution system.

Con Edison's systems are vulnerable to exceeding system capacity during extreme temperatures; gas systems may experience overloading during extreme cold, and electric systems during extreme heat.

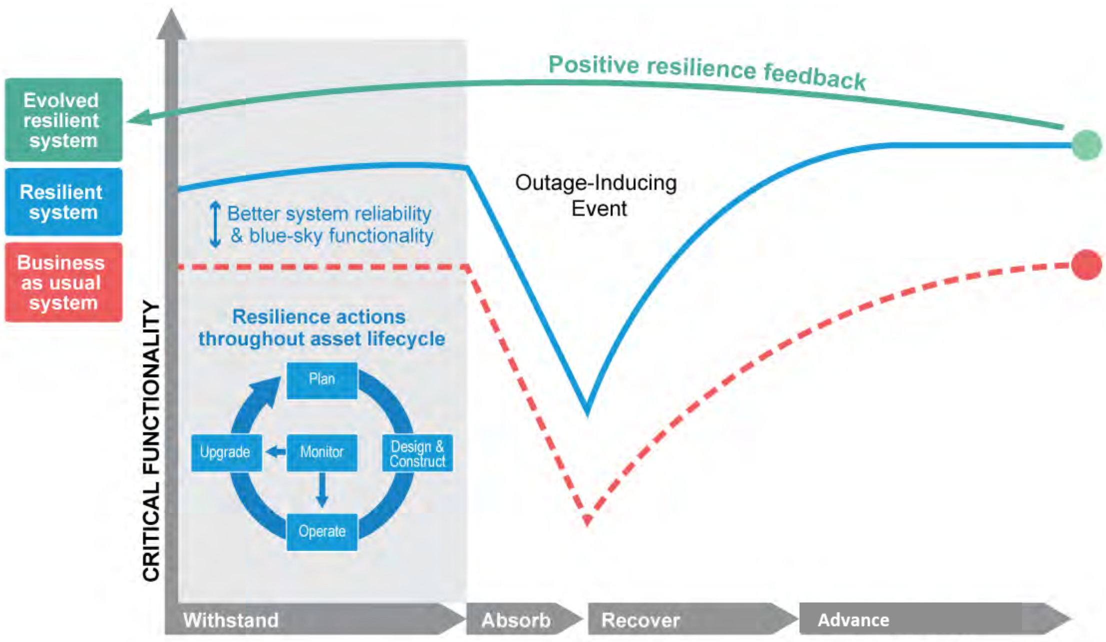
On an operational level, the increasing frequency and intensity of extreme weather events may exceed Con Edison's currently robust emergency preparedness efforts. Con Edison's current "full-scale" response, which calls for all Con Edison resources and extensive mutual assistance, is initiated when the number of customers out of service reaches approximately 100,000. However, low-probability extreme events can increase customer outages and outage durations by orders of magnitude, outpacing current levels of emergency planning and preparedness.

Resilience Management Framework

A resilience management framework will help Con Edison build resilience over time.

To conceptualize how to systematically address vulnerabilities, the Study team developed a resilience management framework (Figure 2). The framework encompasses investments to better withstand changes in climate, absorb impacts from outage-inducing events, recover quickly, and advance to a better state. The "withstand" component of this framework prepares for both gradual and extreme climate risks through resilience actions throughout the life cycle of the assets. As such, many adaptation strategies fall under this category. Investments to increase the capacity to withstand also provide critical co-benefits such as enhanced blue-sky functionality and reliability of Con Edison's systems. The resilience management framework facilitates long-term adaptation and creates positive resilience feedback so that Con Edison's systems achieve better functionality through time. To succeed, each component of a resilient system requires proactive planning and investments.

Figure 2 ■ Conceptual figure representing a resilience management framework designed to withstand changes in climate, absorb and recover from outage-inducing events, and advance to a better state. Most resilience actions should occur systematically throughout the asset life cycle to enhance the ability to withstand changes in climate, while also enhancing system reliability and blue-sky functionality. Resilient systems also adapt so that the functionality of the system improves through time (green line). Each component of a resilient system requires proactive planning and investments.



Adaptation Measures to Address Vulnerabilities

Con Edison already has undertaken a range of measures to build resilience; this Study identified additional adaptation options to address vulnerabilities under a changing climate.

Con Edison has already undertaken a range of measures to increase the resilience of its systems. For example, lessons learned and vulnerabilities exposed during past events, including Superstorm Sandy (2012) and the back-to-back nor'easters (winter storms Riley and Quinn, 2018), resulted in significant capital investments to harden the system. Looking forward, as Con Edison is investing in the system of the future—one with greater monitoring capabilities, flexibility, and reliability—it is simultaneously building a system that is more resilient to extreme weather events and climate change. In addition to new investments, Con Edison also conducts targeted annual updates to its system to ensure capacity and reliability, which help the company keep pace with recent changes in temperature and humidity.

Withstand Gradual Changes in Climate and Extreme Events

Resilience actions should occur systematically throughout an asset's life cycle to enhance the ability to withstand changes in climate while also enhancing system reliability and blue-sky functionality. This can be accomplished through planning, designing, and upgrading assets in a resilient manner, with ongoing monitoring throughout.

Plan

Incorporating climate change projections into Con Edison's routine planning processes will help identify capital needs and help the systems gradually adjust to changes in climate. Some of the types of planning processes and tools that may benefit from consideration of climate change include the following:

- Load and volume forecasting for all commodities
- Load relief planning for the electric system, which should include reduced system capacity and higher load due to warmer temperatures
- Working with utilities in other environments to understand how they plan and design their system for the climate Con Edison will experience in the future
- Long-range planning for all commodities
- Network reliability modeling and planning

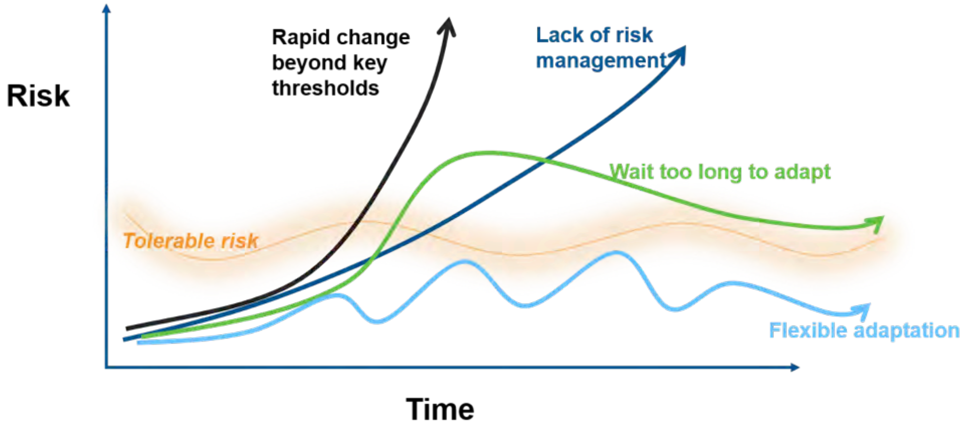
Design

The key to designing resilient infrastructure is to update design standards, specifications, and ratings to account for likely changes in climate over the life cycle of the infrastructure. While there is uncertainty as to the exact changes in climate an asset will experience, selecting an initial climate projection design pathway allows engineers to design infrastructure in line with Con Edison's risk tolerance. The Study team suggests an initial climate projection design pathway that follows the 50th percentile merged RCP 4.5 and 8.5 projections for sea level rise and high-end 90th percentile merged RCP 4.5 and 8.5 projections for heat and precipitation.

Upgrade

Changing design standards will influence the construction of new assets but does not address the vulnerability of existing assets. A flexible and adaptive approach to managing and upgrading assets will allow Con Edison to manage risks from climate change at acceptable levels, despite uncertainties about future conditions. The flexible adaptation pathways approach allows Con Edison to adjust adaptation strategies as more information about climate change and external conditions that may affect Con Edison's operations is learned over time. Figure 3 depicts how flexible adaptation pathways are based on flexible management to maintain tolerable levels of risk.

Figure 3 ■ Flexible adaptation pathways in the context of tolerable risk and risk management challenges to non-flexible adaptation. Adapted from Rosenzweig & Solecki, 2014.



As conditions change over time, Con Edison will need to consistently track these changes to identify when decision making for additional or alternative adaptation strategies is required. This approach relies on monitoring indicators, or "signposts," that provide information which is critical for adaptive management decisions. Broad categories of signposts that Con Edison should consider monitoring include climate variable observations and best available climate projections; climate impacts; and policy, societal, and economic conditions. Predetermined thresholds for these conditions signal the need for a change in action, which support decisions on when, where, and how Con Edison can take action to continue to manage its climate risks at an acceptable level. The body of this report provides many specific examples of proactive investments in resilience and their signposts; a few selected examples are provided in Table 1.

Table 1 ■ Examples of adaptation strategies to upgrade existing infrastructure and signposts to trigger action

Strategy	Signpost
Implement electric reliability strategies, such as: • Split the network into two smaller networks. • Create primary feeder loops within and between networks. • Install a distribution substation. • Incorporate distributed energy resources and non-wires solutions. • Design complex networks that consider combinations of adaptation measures.	Forward-looking network reliability index exceeds 1 per unit
Upgrade HVAC systems.	End of the existing asset's useful life
Retrofit ventilated equipment with submersible equipment to eliminate the risk of damage from water intrusion.	Expanded area of precipitation-based flooding; better maps of areas at risk of current and future precipitation-based flooding
Replace limiting wire sections with higher rated wire to reduce overhead transmission line sag during extreme heat wave events. Alternatively, remove obstacles or raise towers to reduce line sag issues.	Increased incidence of line sag; higher operating temperatures
Strategically expand program to elevate gas regulator vent line termini to include additional regulators exposed to floodplains associated with stronger storms and inland flooding.	When sea level rise exceeds 1 foot; reported or observed flooding in vicinity of asset without vent line protectors

Absorb and Recover from the Impacts of Extreme Events

It is neither efficient nor cost-effective for Con Edison to harden its systems to withstand every type of extreme event. Instead, Con Edison must use a broader suite of adaptation strategies to absorb and recover from the inevitable disruptions caused by extreme events exceeding their design standards. Con Edison currently incorporates “absorb” into its design and operations with, for example, a limited ability to control customer demand and shed load in extreme cases. A broader suite of strategies focuses on emergency preparedness, limiting customer impact and improving customer coping, including the following:

- Supporting the creation of resilience hubs (spaces that support residents and coordinate resources before, during, and after extreme weather events (Baja, 2018) and have continued access to energy services)
- Using smart meters to implement targeted load shedding to limit the impact to fewer customers during extreme events
- Strengthening staff skills for streamlined emergency response
- Planning for resilient and efficient supply chains
- Coordinating extreme event preparedness plans with external stakeholders
- Incorporating low-probability events into long-term plans
- Expanding extreme heat worker safety protocols
- Examining and reporting on the levels of workers necessary to prepare for and recover from extreme climate events
- Investing in energy storage, on-site generation, and energy efficiency programs

Advance

Advancing to a better adapted, more resilient state after an outage-inducing event (i.e., building back better/stronger) begins with effective pre-planning for post-event reconstruction. Even with proactive resilience investments, events can reveal system or asset vulnerabilities. Where assets need to be replaced during recovery, having a plan already in place for selection and procurement of assets designed to be more resilient in the future can help to ensure that Con Edison is adapting to a continuously changing risk environment. Outage-inducing events also provide important opportunities to measure the performance of adaptation investments, helping to inform additional actions that further resilience.

Next Steps

In 2020, Con Edison will develop an implementation plan that details priority actions needed in the next 5, 10, and 20 years.

As a next step from this Study, Con Edison will develop a detailed Climate Change Implementation Plan to integrate the recommendations from this Climate Change Vulnerability Study. The implementation plan will be developed in close coordination with Con Edison SMEs and will utilize quarterly meetings with external stakeholders. The implementation plan will consider updates in climate science, finalize an initial climate design pathway, integrate that pathway into company specifications and processes based on input from subject matter experts, develop a timeline for action with associated costs and signposts, and recommend a governance structure. Some key items for consideration in the implementation plan include determining the appropriate amount of proactive investment, changes in the policy/regulatory and operating environment and the establishment of a reporting structure.

Introduction

Study Background and Objectives

Con Edison's resilience to climate change has important implications for increasingly interconnected societal, technological, and financial systems that the company serves. Developing a shared understanding of Con Edison's vulnerability to climate change is critical to ensuring the continued strength of the company over the coming century. The Con Edison Climate Change Vulnerability Study (Study) has three primary goals:

1. Develop a shared understanding of new climate science and projected climate and extreme weather for the territory.
2. Assess the risks of potential climate change impacts on Con Edison's operations, planning, and physical assets.
3. Review a portfolio of operational, planning, and design measures, considering costs and benefits, to improve resilience to climate change.

The Study was conducted as an outcome of the 2013 rate case. In 2013, Con Edison worked with a Storm Hardening and Resiliency Collaborative in parallel with the rate case to provide parties with an opportunity to fully examine proposals for plans to protect against storms. In 2014, the New York State Public Service Commission approved an Order and funding for Con Edison to implement measures to plan for and protect its systems from the effects of climate change, including conducting a climate change vulnerability study. The Study was developed by the Con Edison Department of Strategic Planning, in collaboration with ICF's climate adaptation and resilience experts and Columbia University's Lamont-Doherty Earth Observatory. The members of this partnership are collectively referred to as the Study team. The Study team relied on inputs and expertise from Con Edison subject matter experts (SMEs), including engaging more than 100 SMEs through a series of in-person meetings, teleconferences, and workshops.

Guiding Principles

The Study used six key principles to efficiently meet its objectives and benefit Con Edison. The Study employed a decision-first and risk-based approach, applying the best available climate science to produce flexible and adaptive solutions and mitigate risks associated with climate change and extreme weather events. The Study process was transparent and interactive to ensure that it can be replicated and institutionalized.

Decision-first approach. The Study team used a decision-first approach, which focuses on understanding the broader vulnerabilities and constraints of the system, the objectives and needs of stakeholders, and the adaptation options available, before considering the projected changes in future climate. The Study team first identified the needs of decision makers (i.e., Con Edison leadership and SMEs) and worked from there to determine information requirements based on decision goals, instead of starting by amassing as much data as possible. This approach places a higher priority on understanding the decision-making context and providing enough information to inform those decisions, which helps to prioritize near- and long-term risks and develop effective solutions despite the existence of deep uncertainties related to future climate change.

Risk-based approach. The Study team employed a risk-based approach that considers both the likelihood and the consequence of potential changes in the climate. This involves identifying a comprehensive set of plausible future climate outcomes and assessing their probability and associated impact on Con Edison's service territory. Doing so allows Con Edison to assess its vulnerability to—and to prepare for—*high-probability and low-impact*, as well as *low-probability and high-impact*, outcomes.

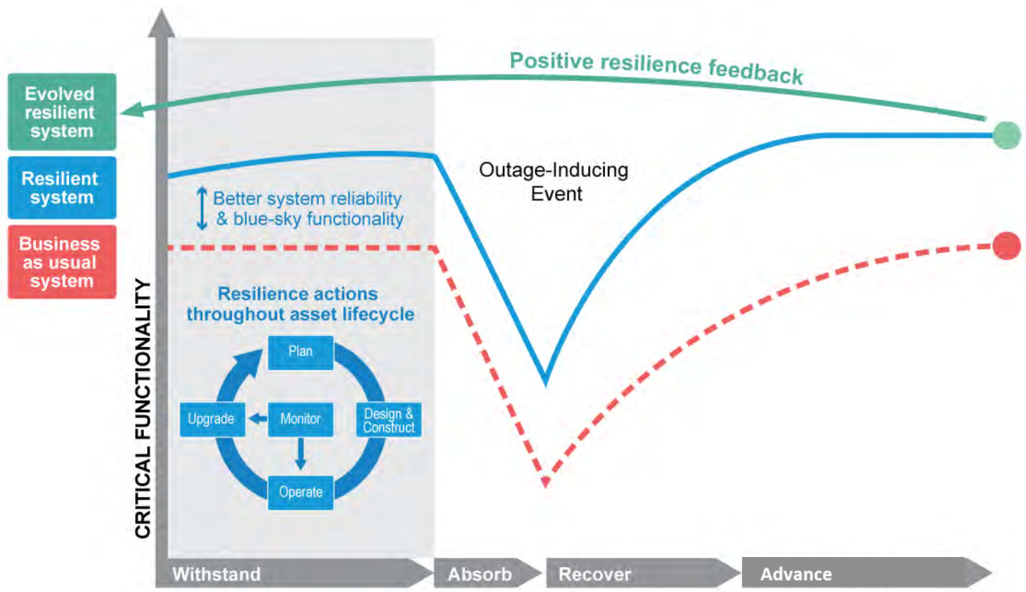
Best available climate science. The Study team prioritized continuous dialogues among climate scientists, climate adaptation specialists, and Con Edison SMEs to identify which climate scenarios, time periods, hazards, variables, and thresholds are important for Con Edison's operations, infrastructure, and planning. The Study team assessed multiple lines of evidence to capture historical climate conditions in the territory and employed a comprehensive set of Global Climate Models to identify the extent to which current climate conditions may change throughout the 21st century. Ultimately, the Study team synthesized climate information into metrics relating plausible effects of climatic changes on operations, infrastructure, and planning.

Transparent and replicable. A transparent and replicable approach allows Con Edison to institutionalize its adaptation strategy and increase its adaptive capacity over time. This will help SMEs establish their adaptation efforts into emerging policies and procedures, as well as train the next generation of SMEs in resilience building. Transparency also engenders trust with internal and external stakeholders.

Flexible solutions and adaptive implementation. A flexible and adaptive approach will allow Con Edison to manage risks from a changing climate at acceptable levels, despite uncertainties about future conditions. Adaptive implementation pathways, or flexible adaptation pathways, are a recognized approach to adaptation planning and project implementation that ensures adaptability over time in the face of uncertainty: changes in energy demand, technologies, population, and other driving factors, and refinements in the scientific understanding of future climate. Under the adaptive approach, resilience measures can be sequenced over time, allowing Con Edison to protect against near-term changes while leaving options open to protect against the wide range of plausible changes emerging later in the century.

Resilience management framework. The Study introduces a resilience management framework that allows Con Edison to mitigate risks associated with climate changes and extreme weather events most relevant to Con Edison's service territory (Figure 4). Resilient systems are composed of more than hardening measures alone, and instead consider measures that increase resilience throughout the life cycle of outage-inducing climate events. These measures include the system's capacity to "withstand," "absorb," and "recover" from climate risks and "advance" resilience. In this way, the resilient management framework is particularly important for addressing complex extreme events with significant uncertainties and extreme thresholds to build into hardening measures alone. In turn, resilient systems offer critical co-benefits, such as improved system reliability and blue-sky functionality, reduced consequences from non-climatic risks, and more resilient customers. A resilience management framework also facilitates long-term adaptation, which enhances the critical functionality of the system through time and creates positive resilience feedback. To succeed, each measure of a resilient system requires proactive planning and investments.

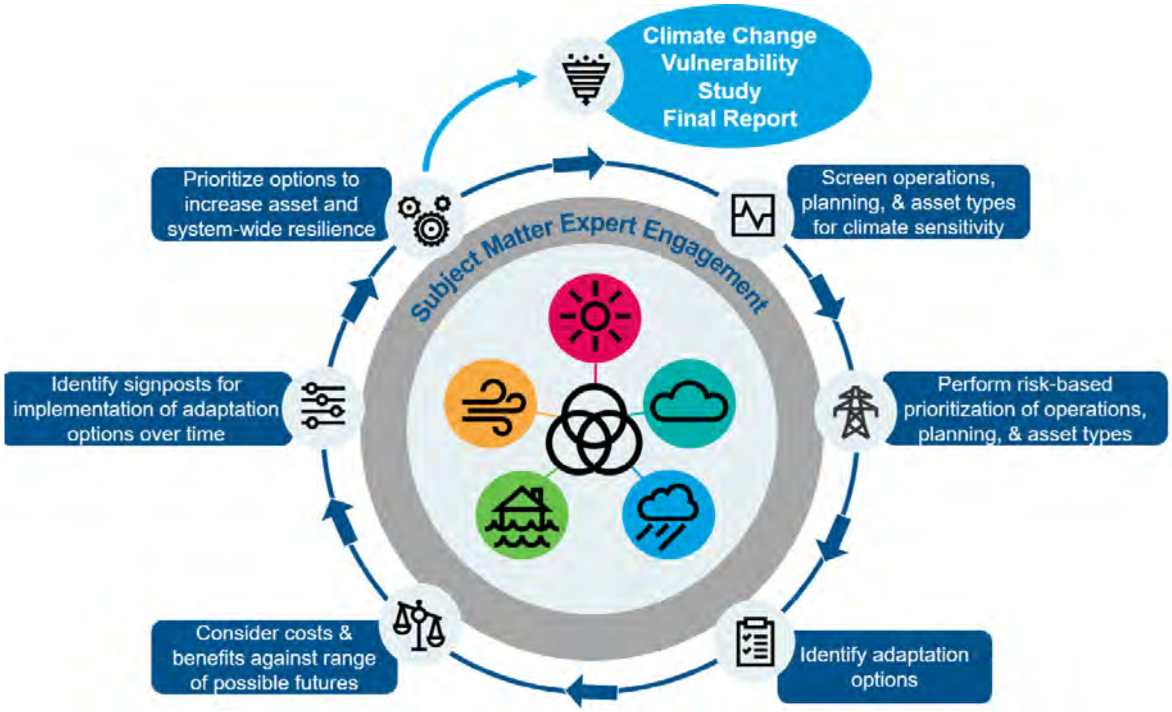
Figure 4 Conceptual figure representing a resilience management framework designed to withstand changes in climate, absorb and recover from outage-inducing events, and advance to a better state. Most resilience actions should occur systematically throughout the asset life cycle to enhance the ability to withstand changes in climate, while also enhancing system reliability and blue-sky functionality. Resilient systems also adapt so that the functionality of the system improves through time (green line). Each component of a resilient system requires proactive planning and investments.



Study Methodology

The Study uses an integrated approach, with Con Edison SMEs providing support throughout the process. A rapid screen of the sensitivity of operations, planning, and assets (referred to for simplicity as "assets" throughout the rest of this document unless otherwise stated) for each climate change hazard provided the basis for a risk-based prioritization of assets. The Study team performed detailed analyses for the sensitive assets, including identifying a portfolio of adaptation options and qualitatively considering the financial costs, co-benefits, and resilience of each option. These detailed analyses will inform the development of flexible solutions and the further prioritization of assets and options to increase systemwide resilience during the creation of Con Edison's Climate Change Implementation Plan in 2020. Figure 5 depicts the Study's general approach.

Figure 5 ■ General approach overview: The process cycles through steps for each climate hazard, beginning with 'Screen operations, planning, and asset types for climate sensitivity'. The process results in the Climate Change Vulnerability Study Final Report.



Screen operations, planning, and asset types for climate sensitivity. The Study began by establishing and confirming a clear set of climate change hazards and relevant thresholds for operations, planning, and asset types. The study team engaged SMEs to identify the extent to which each climate change hazard is a factor in asset design or operation and rate sensitivities by considering impacts from previous weather events and key climate information used in design or operation. Only assets with high sensitivity were considered in the subsequent risk-based prioritization process.

Perform risk-based prioritization of operations, planning, and asset types. Following the high-level screen for sensitivity, the Study team sought to prioritize operations, planning processes, and asset types for further analysis.

- Heat and humidity: Heat and humidity design standards vary across Con Edison assets, so the Study team used a risk workbook to guide SMEs through a structured process to identify the *probability of impact* (based on the probability of exceeding thresholds and the impact of threshold exceedance) and the *consequence of impact*. Together, these components create an *overall risk score* for each relevant asset and climate change hazard combination. *Consequence* is defined as the likely impact to the overall system given the possibility for damage or failure of the particular asset, and includes reliability, safety, environmental damage, and financial costs to the company or customers. The Study team identified several asset types and variable combinations with high sensitivity and high overall climate risk to carry forward as priorities in the analysis.
- Sea level rise and storm surge: Sea level rise and storm surge is a geographically defined hazard with a common design standard across all Con Edison assets. As such, there was a need to

identify potentially exposed assets rather than prioritize among them. The Study team used Geographic Information System (GIS) modeling to evaluate the specific type and number of assets that would be exposed under various future scenarios.

- Precipitation: Very few of Con Edison's assets have design standards tied to precipitation. For the few that were identified, the Study team evaluated whether the assets would withstand future increases in the intensity of precipitation events. In addition, the Study team worked with Con Edison SMEs to identify and prioritize the operational impacts of precipitation on the various commodities.
- Extreme events: By definition, the extreme events analyzed in the study exceed all existing Con Edison design standards. As such, the Study team conducted a workshop with SMEs to prioritize extreme event risks based on the following:
  - The potential for impacts on operations, planning, and assets
  - How prior major weather events affected assets and operations
  - The preparations that Con Edison has in place for future extreme events
  - How longer or more intense events might overwhelm current preparedness efforts

Identify adaptation options. For the identified vulnerabilities, the Study team developed adaptation response options through SME engagement, review of relevant literature, and lessons learned from adaptation options implemented in regions with similar challenges. Adaptation options include strategies to withstand a changing climate, such as engineering design, operations, and planning strategies, as well as strategies to absorb and recover from extreme events. The Study team considered adaptation options that are often already in use to manage the hazard, but which may require revision or updating to deal with changing risk. The Study team also considered both short-term and long-term solutions and took steps to understand and assess the limitations of adaptation options.

Consider costs and benefits of adaptation options against a range of possible futures. The Study team worked with SMEs to develop order of magnitude costs of the various adaptation strategies, where feasible. Where possible, the Study team conducted a multi-criteria analysis of the adaptation options to compare criteria that may be difficult to quantify or monetize, or that may not be effectively highlighted in the financial analysis.

Identify signposts for implementation of adaptation options over time. Evaluation of adaptation measures in the context of a continuously changing risk environment poses a challenge to typical project planning, design, and execution. It is important to ensure that decision-making processes support flexible solutions that allow for effective risk management in the face of irreducible uncertainties in projections of future climate conditions. The Study uses an adaptive implementation pathway approach to achieve this goal. The Study team designed a framework for "signposts," which represent information that will be tracked over time to help Con Edison understand how climate, policy, and process conditions change and, in turn, trigger additional action.

Prioritize options to increase asset and systemwide resilience. Once the prior steps were completed, the Study team circulated the findings to SMEs to allow them to strike, add, or refine strategies. This process resulted in the prioritized set of strategies included in this report.

Historical and Future Climate

Con Edison in a Changing Climate

Earth's climate is not static; it changes in response to both natural and human-caused drivers. The past decade was the warmest on record, and global atmospheric warming has increased at a faster rate since the 1970s (GCRP, 2017), which the global climate science community attributes to increasing human-caused greenhouse gas emissions (IPCC, 2013).

A growing body of research reveals that a range of climate hazards will likely increase in frequency and intensity as a result of atmospheric warming (GCRP, 2017; IPCC, 2013). For example, a warmer atmosphere increases the frequency, intensity, and duration of heat waves; holds more water vapor for heavy precipitation events; and accelerates ice loss from Earth's large ice sheets, contributing to sea level rise and coastal storm surge. These climate changes highlight how changes in the global climate system affect local climatology and weather in Con Edison's service territory. Local changes include both long-term mean changes, such as gradual increases in temperature and sea level, and changes in extreme events, such as heat waves, hurricanes, and storm surge. In most cases, long-term climate change amplifies and increases the likelihood of extreme events. In turn, climate changes and baseline climate hazards cause both direct (e.g., physical damage to infrastructure) and indirect (e.g., changing customer behavior) impacts across the electric, gas, and steam systems of Con Edison's business.

Rapid climate change will bring new challenges to Con Edison through the 21st century. This Study develops climate projections to characterize these challenges. Still, conceptualizing climate change in tangible terms is notoriously difficult. Another way to describe potential climate change is through climate analogs, which match expected future climate change at a location to current climate conditions in another. Under this perspective, New York City's temperature and precipitation by 2080 could more closely resemble current conditions in southern cities such as Memphis, TN, and Little Rock, AR, if greenhouse gas emissions continue unabated (Fitzpatrick & Dunn, 2019).[4]

[4] Climate analogs are illustrative and vary depending on the choice of evaluation metrics, decade, and climate scenario. In this case, analogs are determined using metrics for seasonal minimum and maximum temperature and total precipitation.

Con Edison's Understanding and Assessment of Climate Change

The Study team developed improved, downscaled climate projections and used best available science to understand and evaluate climate change trends and potential extreme weather events across Con Edison's service territory over near- (2030), intermediate- (2050), and long-term (2080) time horizons.[5] This approach builds on methods used by the New York City Panel on Climate Change (NPCC) and introduces a range of benefits (see Table 2). The Study team focused on climate variables that could present outsized impacts to operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business. These include temperature, humidity, precipitation, sea level rise and coastal flooding, extreme events, and multiple—or compounding—events.

The primary tools for understanding future climate change are Global Climate Models (GCMs), which mathematically simulate important aspects of Earth's climate, such as changes in temperature and precipitation, natural modes of climate variability (e.g., El Niño and La Niña events), and the influence of human greenhouse gas emissions (GCRP, 2017). Over short timescales (i.e., years to decades), individual GCM projections can differ from one another due to unpredictable natural climate variability, differences in how models characterize small-scale climate processes, and their response to greenhouse gas emissions/concentration assumptions. For these reasons, future climate analyses often consider a large ensemble of GCMs to better discern long-term trends, account for uncertainty, and consider a fuller range of potential future climate outcomes. To this end, the Study team used a broad model ensemble (i.e., 32 GCMs) for each climate variable of interest to address the spread across models and provide a comprehensive view of future climate.

While GCMs use a finer spatial resolution than ever before, they still provide coarse-resolution estimates of future climate, with model grid cells typically extending approximately 100 kilometers on one side. To achieve a more accurate representation of local climate in the New York Metropolitan Region, the Study team bias-corrected and downscaled GCM projections (i.e., statistically adjusted simulations to bring them closer to observed data) using weather station data over a 1976–2005 historical reference period from three weather station locations spanning Con Edison's service territory, including Central Park, LaGuardia Airport, and White Plains Airport.[6]

GCM simulations are driven by a standard set of time-dependent greenhouse gas concentration trajectories called Representative Concentration Pathways (RCPs), developed by the Intergovernmental Panel on Climate Change (IPCC). RCPs consider different evolutions of fossil fuels, technologies, population growth, and other controlling factors on greenhouse gas emissions through the 21st century. To acknowledge uncertainty in future greenhouse gas concentrations, the Study team selected the commonly used RCPs 4.5 and 8.5 to drive each GCM, following precedent set by IPCC and NPCC. RCP 4.5 represents a moderately warmer future based on a peak in global greenhouse gas emissions around 2040. In contrast, RCP 8.5 represents a hotter future

[5] Columbia University's Lamont-Doherty Earth Observatory led the analysis of temperature, humidity, and precipitation projections and extreme event information. ICF provided insights into future climate conditions using localized constructed analog (LOCA) projections, analyzed sea level rise projections, and synthesized extreme event narratives. Jupiter Intelligence provided projections of extreme temperatures and the urban heat island effect.
[6] Technical information regarding bias-correction and downscaling methods used in this Study are provided in the appendices for the relevant climate variables.

corresponding to “business as usual” increases in greenhouse gas concentrations through the century.

The Study team used a model-based probabilistic framework to evaluate climate change hazards and account for model uncertainty under different RCP scenarios. Specifically, the Study team analyzed high-end estimates (e.g., the 90th percentile of projections across climate models), and mid-point (50th percentile) and low-end (10th percentile) projections for both RCPs. In doing so, the Study Team considered the range of potential climate outcomes across models and RCPs to form a comprehensive risk-based approach. Under this framework, the RCP 8.5 90th percentile approximates a stress test to characterize low probability, high-impact climate change, and its impact on Con Edison.

This Study builds on the approach used by NPCC. Table 2 provides a high-level overview of climate information advances developed as part of this Study.

Table 2 ■ Overview of climate projection methods in this Study relative to the NPCC2 (2015) climate projections of record for New York City

NPCC2 (Reference Projections)	Con Edison Study
Combined projections from two scenarios (RCPs 4.5 and 8.5)	Separate scenario projections
Four time periods (2020–2080)	Seven time periods (2020–2080) to align with planning processes
Single reference point (Central Park)	Multiple reference points tailored to the service territory (Central Park, White Plains, and LaGuardia)
Downscaling using the “delta method”	Downscaling using “quantile mapping”
Limited set of climate variables	Numerous Con Edison-specific variables and multi-variable projections (e.g., heat plus humidity)

The Study also evaluates Con Edison’s vulnerability to rare and complex extreme events, such as major hurricanes and long-duration heat waves, that may increase in intensity and frequency as a result of climate change. Such events play an outsized role in shaping the public’s perception of climate change vulnerability and how institutions should address its unique challenges. While the Study team uses model-based probabilistic projections to inform many climate variables, such as long-term mean temperatures and sea level, it is more challenging to project the rarest events, such as a 1-in-100-year heat wave, and multi-faceted and difficult to model events such as hurricanes. Obstacles to modeling rare and complex extreme events include the brevity of the historical record relative to the rarity of the event, and challenges associated with modeling extremes that have important features at very small space and time scales.

To address these challenges, the Study team constructed a series of extreme event narratives based on historical analogs and the best available climate science. In contrast with model-based probabilistic projections, narratives represent plausible future worst-case scenarios[7] meant to stress-test Con Edison's system. The narratives merge a decision-first and risk-based approach, blending best available science with decision maker-defined high impacts to develop a better understanding of Con Edison's vulnerability to rare, complex extreme events.

Overview of Climate Science Findings Relevant to Con Edison

The Study team's analysis characterized historical and future changes in temperature, humidity, precipitation, sea level rise, and extreme events within Con Edison's service territory. This information supports a risk-based understanding of potential climate-related vulnerabilities within the company's operations, planning, and physical assets. The sections below provide an overview of projected climate changes relevant to Con Edison. While projections were prepared for Central Park, LaGuardia, and White Plains as described above, this section commonly uses Central Park as a reference point due to its central location and because it currently serves as a reference point for many Con Edison operations. The report appendices contain detailed information on other locations and the full scope of climate projections and corresponding vulnerabilities developed for this Study.

The timing and magnitude of climate change over the coming century remains uncertain, particularly with respect to rare and multi-faceted extreme events. This uncertainty presents challenges for institutions such as Con Edison in understanding the potential effects of climate change and the associated risks to their business, operations, and financial performance.

Scenario analysis is a proven way to address these challenges. For example, Task Force on Climate-Related Financial Disclosures (TCFD) scenarios use forward-looking projections to provide a framework to help companies prepare for risks and opportunities brought about by climate change. The scenarios used in this Study are similarly hypothetical constructs, but differ from TCFD scenarios in that they provide quantitative details regarding future extreme event conditions (e.g., regarding specific storm characteristics) so that Con Edison can better plan for specific impacts to assets and infrastructure. Ultimately, this Study uses both climate science and stakeholder-driven perspectives to develop plausible, high impact worst-case scenarios designed to stress-test Con Edison's system.

Temperature

Both average and maximum air temperatures are projected to increase throughout the century relative to historical conditions (Figure 6). Climate model projections reveal significant increases in the number of days per year in which average temperatures exceed 86°F (up to 26 days per year, relative to a baseline of 2 days) and maximum temperatures exceed 95°F (up to 23 days per year from a baseline of 4 days; Figure 7) by 2050. At the same time, winter minimum temperatures are expected to fall below 50°F as many as 40 fewer times per year than in the past by mid-century, representing a 20% decrease.

[7] Worst-case scenarios are meant to explore Con Edison system vulnerabilities related to rare extreme weather events and formulate commensurate adaptation and resilience strategies. Scenarios represent one plausible permutation of extreme weather and the severity of actual events may exceed those considered.

Figure 6 ■ Historic (black line) and projected (colored bands) average air temperature in Central Park during the summer under two greenhouse gas concentration scenarios (RCPs 4.5 and 8.5)

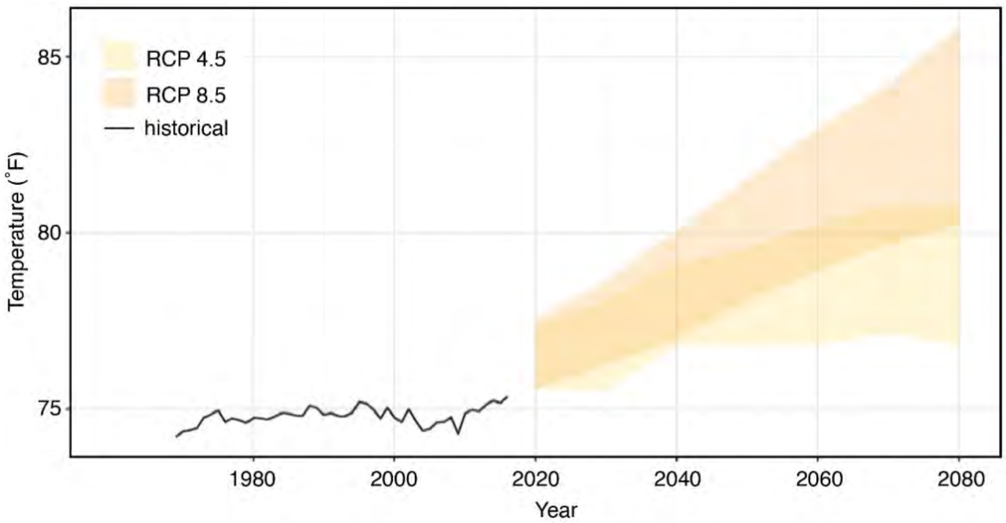
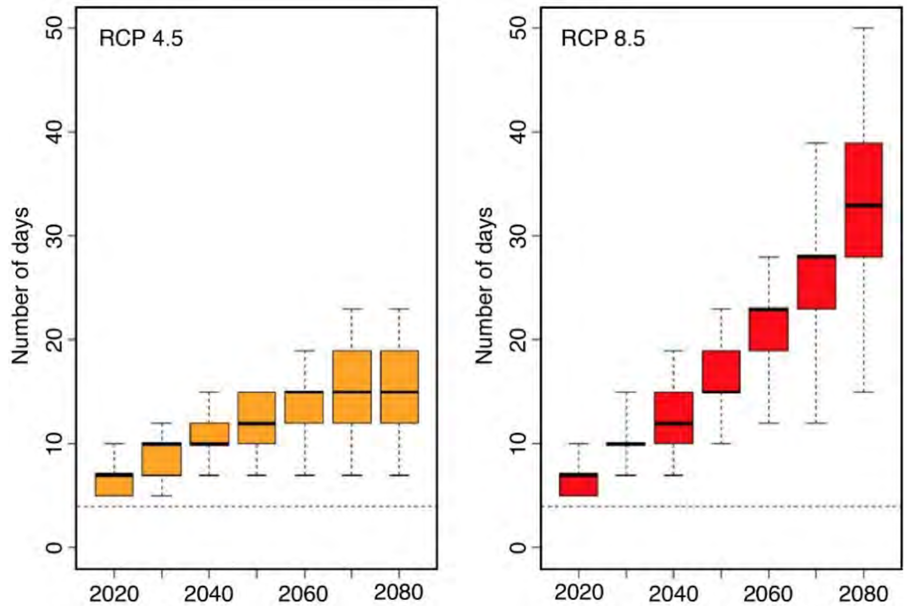


Figure 7 ■ The average number of days per year with maximum summer air temperatures exceeding 95°F in Central Park under two greenhouse gas concentration scenarios (RCPs 4.5 and 8.5). The dashed horizontal lines show the historical average number of days. Box plots correspond to the 10th, 25th, 50th, 75th, and 90th percentile projections.

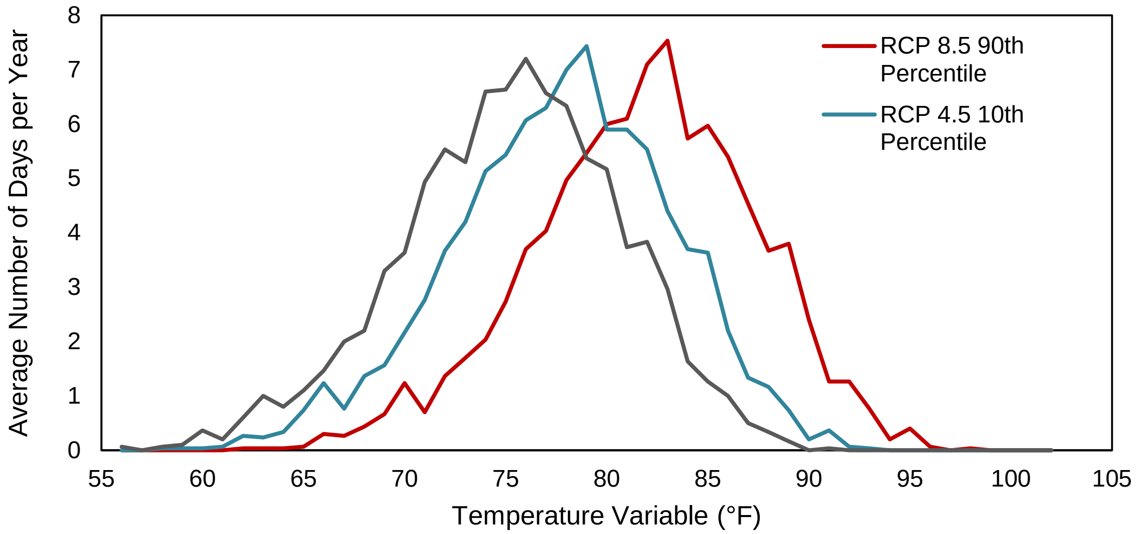


Multi-day heat events, known as heat waves, create potential risks for Con Edison as they drive demand for air conditioning and stress electrical and infrastructure systems. The number of heat waves, defined here as 3 or more consecutive days when *average* temperatures exceed 86°F in Central Park, is projected to increase up to 5 and 14 events per year by 2050 and 2080, respectively, relative to 0.2 events per year historically. The magnitudes of temperature increases are projected to be greatest at LaGuardia and Central Park and smaller at White Plains.

Humidity

The New York Metropolitan Region is susceptible to significant combinations of heat and humidity, which cannot be captured by temperature alone. The combination of temperature and humidity drives electric demand within Con Edison's service territory. To address this, the company currently evaluates the potential for high loads using an index referred to by Con Edison as temperature variable (TV),[8] which incorporates considerations of both temperature and humidity. Looking forward, TV thresholds that have historically occurred only once per year (e.g., 86°F), are projected to become common occurrences within a generation, occurring between 4 and 19 times per year by 2050 and 5 and 52 times per year by 2080, under the RCP 4.5 10th percentile and RCP 8.5 90th percentile, respectively, at LaGuardia (Figure 8). Smaller increases are expected at White Plains.

Figure 8 ■ Distributions showing historical (black line) and 2050 projected (blue and red lines) summer (June–August) daily electric TV at LaGuardia Airport. The 2050 projections show both the RCP 8.5 90th percentile and the RCP 4.5 10th percentile distributions.



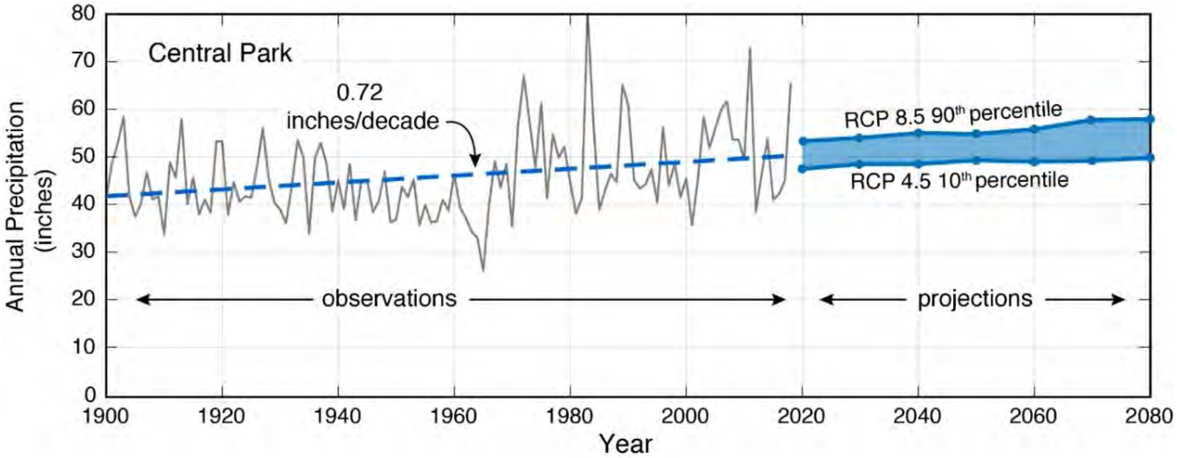
The heat index is a typical indicator of "how hot it feels," which considers the combined effect of air temperature and relative humidity. The index assesses health risks associated with overheating, including for Con Edison employees working under hot conditions. Looking forward, the frequency of occurrence for very high heat index thresholds is projected to increase dramatically through the century. Projections reveal that the number of days per year when the heat index equals or exceeds 103°F at LaGuardia could increase to between 7 and 26 days by 2050 under the RCP 4.5 10th percentile and the RCP 8.5 90th percentile, respectively, compared to only 2 days historically.

[8] Temperature variable is calculated using the weighted time integration of the highest daily recorded 3-hour temperature and humidity over a 3-day period. The reference TV for Con Edison is 86°F, which approximates a heat index of 105°F.

Precipitation

Con Edison's service territory experiences a range of precipitation events over a range of timescales, including rainfall, downpours, snowfall, and ice. Climate change is projected to drive heavier precipitation across these event types because a warmer atmosphere holds more water vapor and provides more energy for strong storms. Looking forward, average annual precipitation is projected to increase by 0% to 15% relative to the historical baseline in Central Park through 2050 (Figure 9).

Figure 9 ■ Observed and projected annual precipitation at Central Park. Projections show potential annual precipitation under both the RCP 8.5 90th percentile and the RCP 4.5 10th percentile. Projections represent 30-year time averages (shown as blue circles), which reveal the long-term trend, but underrepresent year-to-year variability. The dashed line represents the linear trend though the observational record, with observed increases given in inches per decade.



Projections of heavy rainfall reveal similar increases. For example, the heaviest 5-day precipitation amount could be 11.8 inches at Central Park by 2050, which represents a 17% increase over the historical reference period. Data from the Northeast Regional Climate Center[9] show that 25-year, 24-hour precipitation amounts at Central Park, LaGuardia, and White Plains could increase by 7% to 14% and 10% to 21% by mid- and late-century, respectively. Ultimately, projections point to a future defined by more frequent heavy precipitation and downpours, likely accompanied by smaller increases in the frequency of dry or light precipitation days (GCRP, 2017).

Projections for changes in snow and ice are more uncertain than those for rainfall. Overall, models project a decrease in snowstorm frequency corresponding to a warming climate (Zarzycki, 2018). However, while the likelihood of a given storm producing snow instead of rain will decrease in the future, if atmospheric conditions are cold enough to support frozen precipitation, then storms are expected to produce more snow (or ice) than during the present day (Zarzycki, 2018).

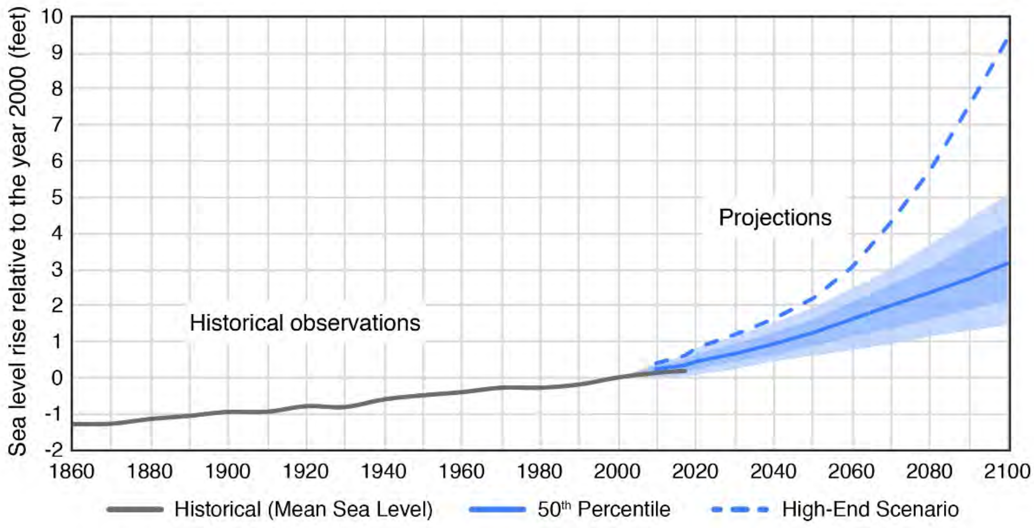
Sea Level Rise

A range of underlying factors, including thermal expansion of the ocean, the rate of ice loss from glaciers and ice sheets, atmosphere and ocean dynamics, and vertical coastline adjustments determine local sea level rise within Con Edison's service territory. State-of-the-art probabilistic

[9] http://ny-idf-projections.nrcc.cornell.edu/

projections (Kopp et al., 2014; 2017) determined these contributions and characterized the rate of future sea level rise in the region under both RCPs 4.5 and 8.5 (e.g., Figure 10). These sea level rise projections include a unique high-end scenario driven by rapid West Antarctic ice sheet mass loss in the later 21st century (DeConto & Pollard, 2016; Kopp et al., 2017). Con Edison has always implemented anti-flooding measures. Following Superstorm Sandy in 2012, the company implemented a minimum protection design standard of "FEMA plus three feet,"[10] allowing for 1 foot of sea level rise. In turn, forward-looking projections determine when sea level rise may exceed Con Edison's established risk tolerance of 1 foot of sea level rise.

Figure 10 Historical and projected sea level rise in New York City under RCP 8.5 relative to the year 2000. The grey line shows historical mean sea level at the Battery tide gage. Projections are relative to the 2000 baseline year. The solid blue line shows the 50th percentile of projected sea level rise. The darker shaded area shows the likely range (17th–83rd percentiles), while the lighter shaded area shows the very likely range (5th–95th percentiles). The blue dashed line depicts a high-end projection scenario driven by rapid West Antarctic ice sheet mass loss in the later 21st century (DeConto & Pollard, 2016; Kopp et al., 2017).



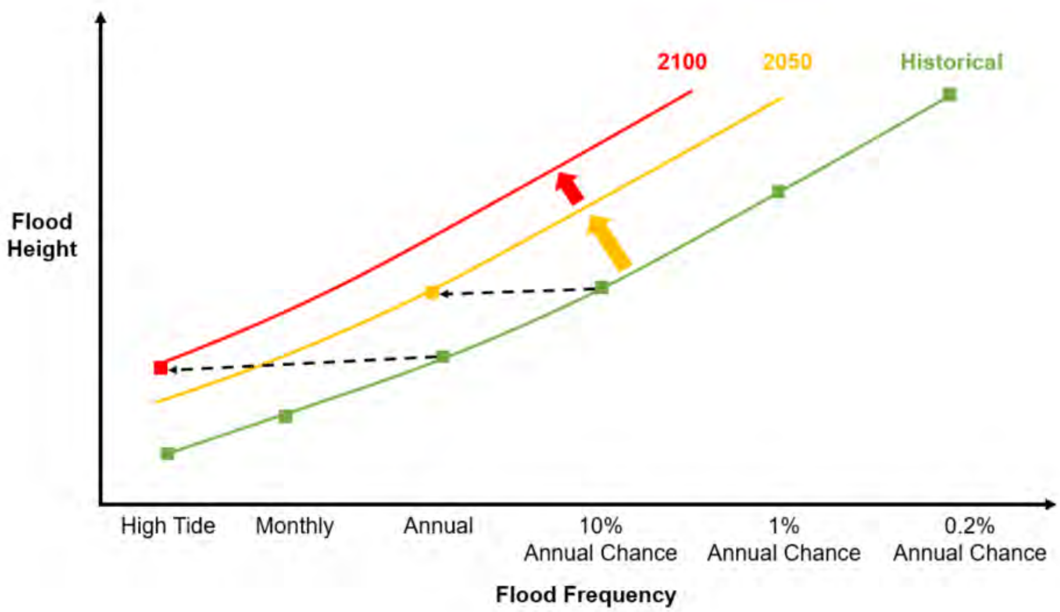
Sea level rise will very likely be between 0.62 and 1.74 feet and 0.62 and 1.94 feet at the Battery tide gauge in lower Manhattan by 2050 under RCPs 4.5 and 8.5, respectively. Projections suggest that Con Edison's 1-foot sea level rise risk tolerance threshold may be exceeded as early as 2030 and as late as 2080.

In turn, rising sea levels will have profound effects on coastal flooding, as sea level rise is expected to increase both the frequency and height of future floods (Figure 11). For example, the flood height associated with the 1% annual chance (100-year) flood in New York City is projected to increase from 10.9 feet to as much as 15.9 feet under RCP 8.5 by 2100, representing an increase of close to 50%.[11] Similarly, today's 0.2% annual chance (500-year) flood could look like a 10% annual

[10] This includes the FEMA 1% annual flood hazard elevation, 1 foot of sea level rise and 2 feet of freeboard (to align with 2019 Climate Resiliency Design Guidelines published by the New York City Mayor's Office of Recovery and Resiliency).
[11] Flood values are above the mean lower low water (MLLW) datum at the Battery tide gauge. MLLW is measured as 2.57 feet below mean sea level at the Battery.

chance (10-year) flood in 2100, making it 50 times more likely. At the end of the century, today's annual chance flood could occur at every high tide.

Figure 11 ■ Projected changes in the frequencies of historical flood heights as a result of sea level rise. Dashed lines represent projected changes in frequency; solid lines represent illustrative changes in flood frequency coinciding with flood heights



Extreme Events

Rare extreme events, such as strong hurricanes and long-duration heat waves, are low-probability and high-impact phenomena that pose outsized risks to infrastructure and services across Con Edison's service territory. While modeling rare extreme events remains challenging and at the forefront of scientific research, a growing body of evidence suggests that many types of extreme events will likely increase in frequency and intensity as a result of long-term climate warming.

To address these challenges, the Study team used feedback from Con Edison SMEs to prioritize a suite of extreme event narratives that combine plausible worst-case events from both climatological and impact perspectives. In turn, the narratives represent future worst-case scenarios designed to stress-test Con Edison and the local and regional systems with which it connects. The chosen narratives considered a prolonged heat wave, a Category 4 hurricane, and an unprecedented nor'easter striking the region.

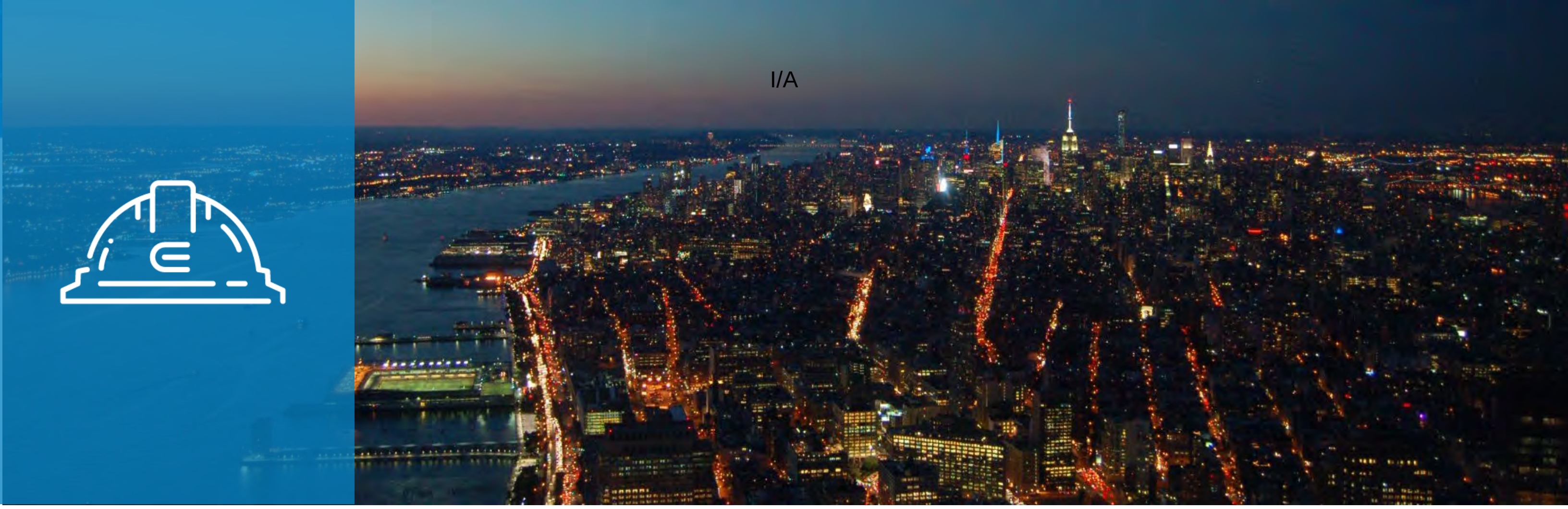
Best available climate science reveals that climate change will likely amplify these extremes over the coming century. For example, the mean heat wave duration in New York City is expected to increase to 13 and 27 days by 2050 and 2080, respectively, based on RCP 8.5 90th percentile projections (NPCC, 2019). At the same time, broadscale atmospheric and ocean surface temperature changes may drive stronger hurricanes and extratropical cyclones. Looking forward, while the total number of hurricanes occurring in the North Atlantic may not change significantly over the next century, the percentage of very strong and destructive (i.e., Categories 4 and 5) hurricanes is projected to increase in the North Atlantic basin (IPCC, 2013). It can therefore be argued that climate change could make it more likely for one of these storms to impact the New York Metropolitan Region, although the most dominant factor will remain unpredictable climate and weather variability (Horton & Liu, 2014). Finally, some recent studies project a 20% to 40% increase in nor'easter strengthening (i.e., producing the types of storms with destructive winds) immediately inland of the Atlantic coast by late-century, suggesting stronger storms may more frequently impact the New York Metropolitan Region with heavy precipitation, wind, and storm surge (Colle et al., 2013)

Signposts: Monitoring and Climate Science Updates

Understanding Con Edison's vulnerabilities to climate change and adapting to those changes over time require a robust monitoring strategy. Climate change evolves through time, meaning that the current spread of potential future climate outcomes produced by models will eventually converge on a smaller set of climate realizations. To keep up with this evolution, a range of signposts are required to sufficiently gauge relevant rates of change and best prepare Con Edison for the most likely climate future.

An awareness of past and present climate conditions in Con Edison's service territory is critical for understanding the trajectory of climate change. Con Edison currently operates a number of stations that monitor climate variables and is finalizing plans to expand the number of monitoring locations. Increasing observations from monitoring stations will help measure both local climate variations and climate change through time, informing Con Edison's climate resilience planning. Citywide observations of variables, such as hourly temperatures, precipitation, humidity, wind speed, and sea level, are paramount to building a broad and usable set of guiding measurements. With accurate and up-to-date data on these variables, Con Edison can better monitor both changing conditions and potential points of vulnerability.

Con Edison can supplement monitoring through a regularly updated understanding of the best available projections as models and expert knowledge evolve over time. Climate projections continually improve as the scientific community better understands the physical, chemical, and biological processes governing Earth's climate and incorporates them into predictive models. Ultimately, Con Edison wants to draw on the best available data and projections that are driven by scientific consensus, but also are accessible and applicable to company needs. Signposts for updating climate science used to inform potential Con Edison vulnerabilities include major science advancements, such as the release of the new Coupled Model Intercomparison Project (CMIP) projections and their integration and validation in new IPCC, NPCC, and National Climate Assessment (NCA) reports. These assessments include updated probabilistic climate projections representing model advancements, the best available science regarding difficult-to-model extreme events, and literature reviews reflecting the current state of science as guided by leading experts. Such signposts could justify Con Edison updating their climate projections of record to reflect the best available science or projections that represent a significant departure from previous understanding. Historically, major scientific reports, such as the IPCC, have been released about every 6 to 7 years, which provide a potential constraint on how frequently Con Edison's understanding of climate change within the service territory might be revisited.



Existing Efforts and Practices to Manage Risks Under a Changing Climate

Although this Study is Con Edison's first comprehensive assessment of climate change vulnerabilities, Con Edison has already undertaken a range of measures to increase the resiliency of its system. Lessons learned and vulnerabilities exposed during past events, most recently Superstorm Sandy (2012) and the back-to-back nor'easters (winter storms Riley and Quinn, 2018), resulted in significant capital investments to harden the system.

In addition, as Con Edison invests in the system of the future—one with greater monitoring capabilities, flexibility, and reliability—it is simultaneously building a system that is more resilient to extreme weather events and climate change. For example, grid modernization will both increase efficiency and enhance monitoring capabilities by employing new technology and modes of data acquisition. Con Edison is planning to support numerous grid modernization initiatives that target energy storage technologies, communications systems, distributed energy resources infrastructure and management, complex data processing, and advanced grid-edge sensors (Con Edison, 2019). Con Edison additionally plans to modernize its Control Center to assume more proactive and centralized management of its complex distribution grid. Throughout these modernization initiatives, the company remains in close collaboration with the City of New York.

Con Edison also conducts targeted annual updates to its system to ensure capacity and reliability. These annual updates help the company keep pace in real time with changes in some key hazards. For example, when conducting electric load relief planning, Con Edison incorporates load forecasts that use an annually updated set of TV data. Although these forecasts are not grounded in future projections that consider climate change, they do account for the most recent climate trends and, as such, allow the company to stay in stride with the most current data.

Con Edison's previous adaptation measures have made targeted improvements in (1) physical infrastructure, (2) data collection and monitoring, and (3) emergency preparedness. The following measures are illustrative of these targeted improvements, but are not meant to be exhaustive of the efforts that Con Edison has undertaken:

Physical Infrastructure

- Adopting the Dutch approach of "defense in depth" after Superstorm Sandy to protect all critical and vulnerable system components from coastal flooding risks, including the following:

- Upgrading and increasing the number of flood barriers and other protective structures
- Reinforcing tunnels
- Replacing equipment with submersible equivalents in flood zones (e.g., targeted main replacement program, gas system)
- Installing pumps and elevating infrastructure behind flood walls

- Protecting or elevating critical electrical infrastructure to the Federal Emergency Management Agency (FEMA) 100-year flood elevation plus 3 feet to account for sea level rise and freeboard during coastal storms
- Undertaking a targeted main replacement program that addresses low-pressure gas mains in low-lying areas, as well as other potentially vulnerable gas mains
- Installing isolation devices to limit the impact of damaged infrastructure on customers by de-energizing more granular sections of the system, when necessary
- Engaging innovative technologies to reduce the impact of extreme weather on electric distribution systems and quicken the recovery, including the following:
  - Demand response technologies that more efficiently regulate load
  - Automated splicing systems that reduce feeder processing times

Data Collection and Monitoring

- Developing programs that employ machine learning and remote monitoring to identify areas of heightened vulnerability in Con Edison's systems, including the following:
  - Leak-prone areas of the gas distribution system
  - Gas system drip pots that require draining
- Initiating a more diligent inspection system that effectively assesses the functionality of assets, as well as their exposure to potential hazards (e.g., nearby vegetation), including the following:
  - Underground network transformers and protectors
  - Underground structures
  - Flushing of flood zone vaults
  - Rapid assessments of overhead feeders
  - Overhead system pole-by-pole inspection for specification compliance
- Future deployment of advanced metering infrastructure (AMI) throughout the service territory has the potential to both improve information flow to customers and help absorb the impacts of extreme events. Specifically, AMI might be able to rapidly shed load on a targeted network to help ensure demand does not exceed supply, which reduces potential damages and likelihood of network-wide outages in the event of an extreme event.

Emergency Preparedness

- Improving contractor and material bases for post-storm repair crews and equipment, including the following:
  - Expanding and diversifying spare material inventories
  - Ensuring that all spare materials are housed in safe locations
- Conducting post-event debriefings to understand the impact of weather conditions on system performance
- Engaging with major telecommunications providers and enhancing communications systems among customer networks
- Facilitating equipment-sharing programs across New York State to ensure access to supplies during emergency response

Con Edison recognizes that the drivers behind future planning operations are inherently uncertain and is committed to both closely monitoring key signposts and continuously updating company investment plans and priorities.

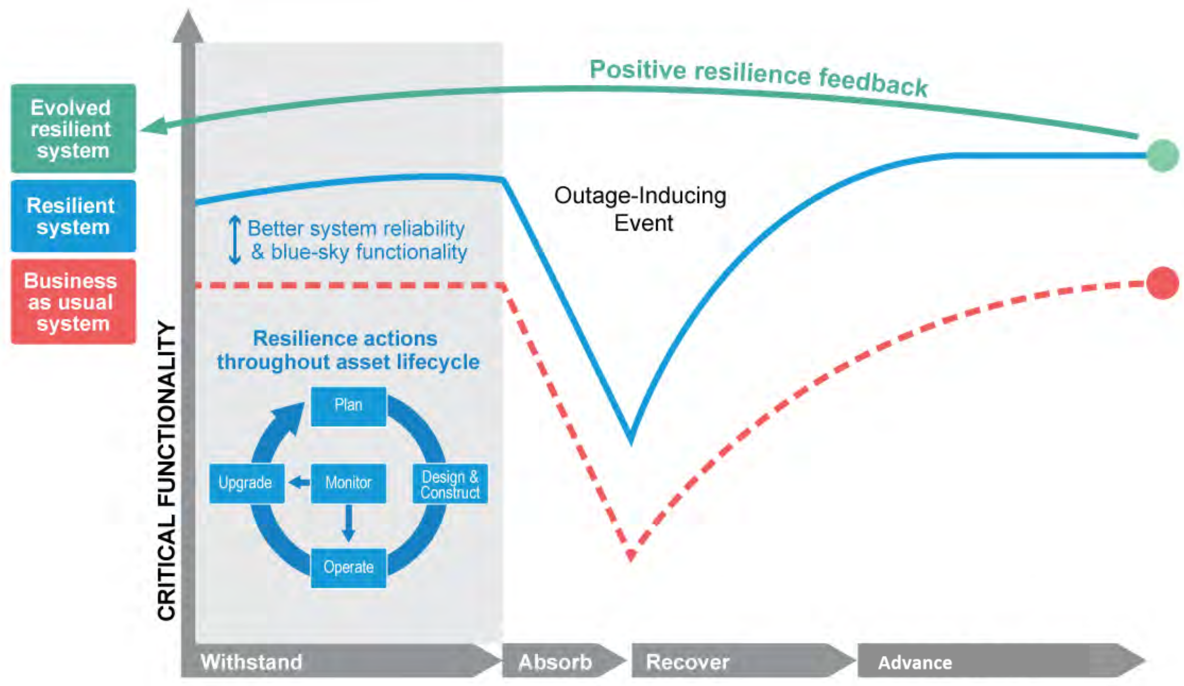
Vulnerabilities, a Resilience Management Framework, and Adaptation Options

Con Edison may face greater vulnerabilities due to future changes in temperature, humidity, precipitation, sea level rise, and extreme weather events. To understand this, the Study team evaluated key vulnerabilities of Con Edison's present-day electric, gas, and steam systems under a changing climate. The physical assets, operations, and planning of each system are uniquely vulnerable. In turn, building a detailed understanding of key vulnerabilities is an important step toward identifying priority adaptation measures.

Resilience Management Framework

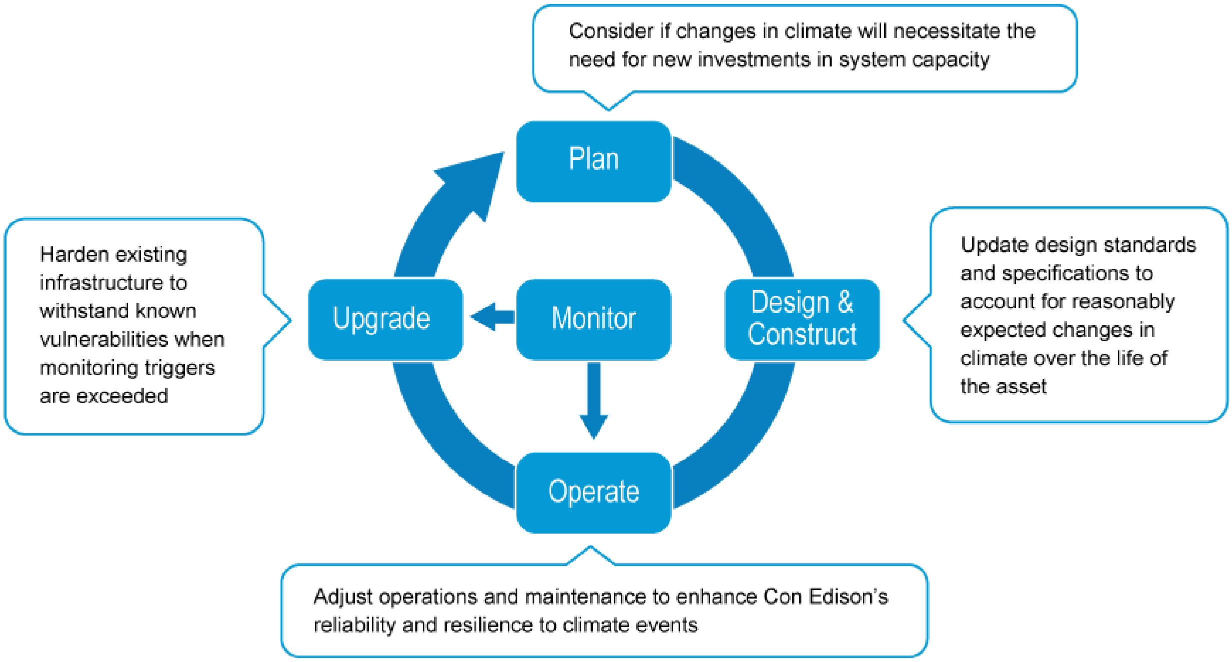
Under a changing climate, Con Edison will likely experience the increasing frequency and intensity of both gradual climate changes and extreme events. In response, the Study team developed a resilience management framework (Figure 12) to outline how a comprehensive set of adaptation strategies would mitigate future climate risks. The framework encompasses investments to better withstand changes in climate, absorb impacts from outage-inducing events, recover quickly, and advance to a better state. The "withstand" component of this framework prepares for both gradual (chronic) and extreme climate risks through resilience actions throughout the life cycle of assets. As such, many of the adaptation strategies identified in the following sections fall under the category of systematically bolstering Con Edison's ability to withstand future climate risks. Investments to increase the capacity to withstand also provide critical co-benefits, such as enhanced blue-sky functionality and the reliability of Con Edison's system. The resilience management framework facilitates long-term adaptation and creates positive resilience feedback so that Con Edison's system achieves better functionality through time. To succeed, each component of a resilient system requires proactive planning and investments.

Figure 12 ■ Conceptual figure representing a resilience management framework designed to withstand changes in climate, absorb and recover from outage-inducing events, and advance to a better state. Investing in a more resilient system (blue line) provides benefits relative to a less resilient, or business-as-usual, system (red dashed line) before, during, and after an outage-inducing event. Most resilience actions should occur systematically throughout the asset life cycle to enhance the ability to withstand changes in climate, while also enhancing system reliability and blue-sky functionality. Resilient systems also adapt so that the functionality of the system improves through time (green line). Each component of a resilient system requires proactive planning and investments.



“Withstand” entails proactively strengthening the system to mitigate and avoid climate change risks and increase the reliability of Con Edison’s system. “Withstand” investments are not necessarily a one-time event. Rather, the ability to withstand climate change must be integrated and revisited throughout the life cycle of Con Edison’s assets. Doing so requires changes in the planning, design, and construction of new infrastructure; ongoing data collection and monitoring; and eventually investing in the upgrade of existing infrastructure, using forward-looking climate information. This life cycle approach to considering climate change is captured in Figure 13. Across Con Edison’s electric, gas, and steam systems, planning for new investments in system capacity serves as a critical and strategic opportunity to integrate climate considerations. In addition, an important aspect of increasing the capacity of new investments to withstand changes in climate is maintaining strong design standards that account for gradual changes in chronic stressors and more frequent extreme events. However, since design standards do not apply to existing infrastructure, a strong monitoring program and signposts for additional adaptation investments could help ensure that Con Edison’s existing infrastructure remains resilient to climate change by informing adjustments to operations and potential needs for upgrades.

Figure 13 ■ “Withstand" actions and investments must be revisited throughout the life cycle of Con Edison's assets.



“Absorb” includes strategies to reduce the consequences of outage-inducing events, since Con Edison cannot and should not harden its energy systems to try to withstand every possible future low-probability, high-impact extreme weather event. These actions, many of which Con Edison is already implementing, include operational changes to reduce damage during outage-inducing events and to protect exposed systems from further damage.

“Recover” aims to increase the rate of recovery and increase customers’ ability to cope with impacts after an outage-inducing event. Such strategies build on Con Edison’s Emergency Response Plans and Coastal Storm Plans. In addition, there is a role that Con Edison can play to increase customer coping and prioritize the continued functioning of critical services. Resilient customers are those who are prepared for outages and are better able to cope with reduced energy service—through measures such as having on-site energy storage, access to locations in their community with power, the ability to shelter in place without power, and/or prioritized service restoration for vulnerable customers.

“Advance” refers to building back stronger after climate-related outages and updating standards and procedures based on lessons learned. Even with proactive resilience investments, outage-inducing climate events can reveal system or asset vulnerabilities. Adjusting Con Edison’s planning, infrastructure, and operations to new and future risks after an outage-inducing event, while incorporating learning, will allow for a more effective and efficient transition to greater resiliency. Con Edison has taken this approach in the past, including investing a billion dollars in storm hardening measures after Superstorm Sandy. Moving forward, restoring service following an outage-inducing climate event to a better adapted, more resilient state begins with effective pre-planning for post-event reconstruction. Where assets need to be replaced during recovery, having a plan already in place for selection and procurement of assets designed to be more resilient in the future can help to ensure that Con Edison is adapting to future extremes in a continuously changing risk environment.

Implementation of adaptation strategies throughout all of these phases will need to be adjusted over time to manage for acceptable levels of risk despite uncertainties about future conditions. The flexible adaptation pathways approach, described in further detail in the subsequent section, ensures the adaptability of adaptation strategies over time as more information about climate change and external conditions becomes available.

All Commodities (Electricity, Gas, and Steam)

Vulnerabilities

The Study team identified priority hazards for each of Con Edison's commodity systems (electric, gas, and steam) and found that several hazards were priorities across all three systems, although these hazards present unique vulnerabilities to the various assets within each system. The hazards common to all three systems are heat index, precipitation, sea level rise and storm surge, and extreme and multi-hazard events. These are discussed below. System-specific vulnerabilities are subsequently discussed in separate sections.

Heat Index

Worker safety may be a point of vulnerability if heat index values rise as projected. The Occupational Safety and Health Administration has set a threshold of 103°F for high heat index risk for people working under hot conditions. During the base period (1998–2017), there were 2 days per year with maximum heat greater than or equal to 103°F (but below 115°F). Under a lower emissions climate scenario (RCP 4.5 10^{th} percentile), the 103°F threshold may be met 5 to 7 days per year by 2050; under a higher emissions scenario (RCP 8.5 90^{th} percentile), this may occur 14 to 20 days per year by 2050. This poses a potential health threat to all Con Edison workers whose duties require outdoor labor.

Projected increases in heat index may also affect cooling equipment across Con Edison's systems, including the HVAC units for Con Edison buildings, air cooling towers for the electric system, and a water cooling tower for Con Edison's East River Steam Generating Plant. In order to supply sufficient cooling to its systems in 2080, Con Edison's HVAC systems will have to increase their capacity by 11% due to projected increases in dry bulb temperature. These systems have a roughly 15-year life span and therefore can be upgraded during routine replacements at an incremental cost of $1.3 million for 157 units. Similarly, Con Edison's cooling towers will have to increase their capacity by 30% by 2050. Cooling towers have a 20- to 35-year life span, allowing them to be upgraded during routine replacements at an incremental cost of $1.1 million for 19 cooling towers at 13 sites.

Precipitation

The Study team conducted an analysis of the physical and operational vulnerabilities of Con Edison's steam system, gas system, and transmission and substation components of the electric system. Findings indicated that all underground assets are vulnerable to flooding damage (i.e., water pooling, intrusion, or inundation) from heavy precipitation occurring over a short period of time. Specific vulnerabilities and their relevant thresholds vary significantly by commodity and, as such, are outlined in their respective sections.

Sea Level Rise and Storm Surge

The Study team broke down evaluation of priority vulnerabilities related to sea level rise into two components.

The first component focuses on design standards for new infrastructure. The Study team assessed Con Edison's coastal flood protection standards for robustness to projected sea level rise. Con Edison's current design standard for coastal flood protections includes the FEMA 1% annual flood hazard elevation, 1 foot for sea level rise, and 2 feet of freeboard, which aligns with New York City's Climate Resilience Design Guidelines for critical infrastructure and water elevations that Con Edison experienced during Superstorm Sandy. Under high-end sea level rise (e.g., due to either rapid ice loss from the West Antarctic Ice Sheet corresponding to Kopp et al., 2017, or RCP 8.5 95th percentile projections corresponding to Kopp et al., 2014), the existing 1 foot sea level rise risk tolerance threshold could be exceeded by 2030; however, under more likely scenarios, the current threshold could be exceeded between 2040 and 2080.[12] The probability that sea level rise will exceed the 1-foot sea level rise risk tolerance by 2020 is under 10%; that increases to 65% to 70% by 2050, and to 100% by the 2080s.

The second evaluation component identified specific physical vulnerabilities of Con Edison's existing assets to impacts related to sea level rise, which are described by commodity below.

Extreme and Multi-Hazard Events

Assets across all systems are vulnerable to possible damage from extreme event flooding. Storm surge driven by an extreme hurricane event (i.e., a Category 4 hurricane) has the potential to flood both aboveground and belowground assets. Specific asset damage varies by commodity and is outlined in the commodity-specific sections. In addition, flooding from ice-melt and snowmelt may cause significant damage to assets across all commodities, especially if the melt contains corrosive road salts.

On an operational level, increasing frequency and intensity of extreme weather events may exceed Con Edison's currently robust emergency preparedness efforts. Con Edison's extreme weather response protocols are specified in the company's hazard-specific Emergency Response Plans and Coastal Storm Plans for electric, steam, and gas systems. Con Edison's current "full-scale" response, which calls for all Con Edison resources and extensive mutual assistance, is initiated when the number of customers out of service reaches approximately 100,000. However, low-probability extreme events can increase customer outages and outage durations by an order of magnitude, outpacing current levels of emergency planning and preparedness, as shown in Figure 14.

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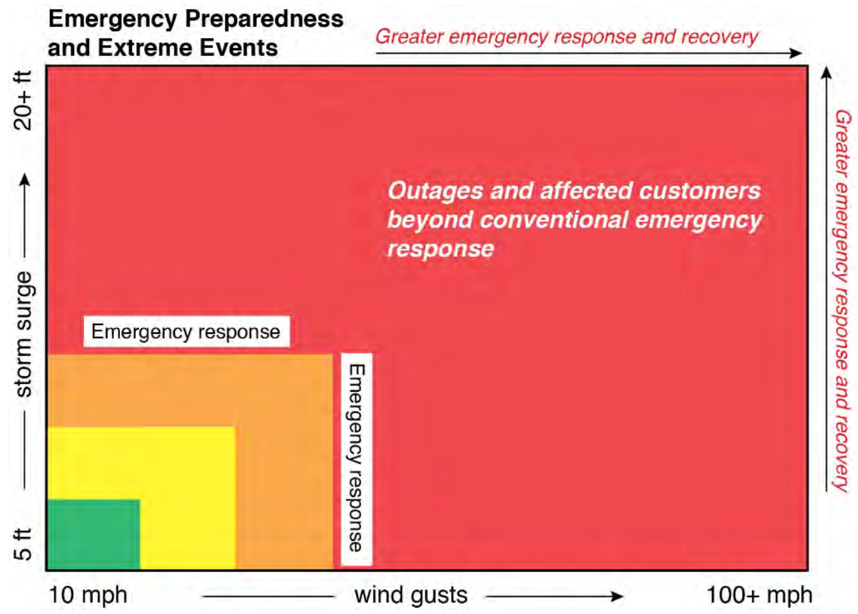
[12] The sea level rise projections use a baseline year of 2000. For more details on these projections and how they relate to Con Edison's design standards, see Appendix 4.

Figure 14 ■ Schematic diagram illustrating the increasing impacts during an extreme event (e.g., hurricane with extreme wind gusts and storm surge) that demands correspondingly large emergency response efforts that may exceed those experienced historically.



Adaptation Measures to Address Vulnerabilities

Several adaptation measures help address vulnerabilities across Con Edison's electric, gas, and steam systems: improved monitoring systems and capabilities to support planning and decision making, emergency preparedness and full system recovery, and improved customer coping.

Improved Monitoring Systems and Capabilities to Support Planning and Decision Making

Con Edison can collect updated and comprehensive data to further strengthen the resilience of its long-term plans and decision-making processes to climate change. Signposts guide planning and decision making, especially through informing the timing of implementation and the adjustment of adaptation measures, described in greater detail in the section below on Moving Towards Implementation.

As previously mentioned, it is important to have the latest information on climate variables and projections as the climate changes and the science improves. Monitoring local climate rates of change across the service territory can help Con Edison better track both changing conditions and potential points of vulnerability across its systems. Specific adaptation measures per commodity that are dependent on the monitoring of climate variable information are detailed in the respective commodity sections. In addition to information on climate variables, Con Edison will need to stay abreast of the latest climate science projections generated by expert organizations such as IPCC, NCA, and NPCC. The Study team suggests that Con Edison could revise its planning and decision-making processes at least every 5 years to incorporate updated climate science information.

Emergency Preparedness and Full System Recovery

Con Edison should consider a range of adaptation strategies to increase capacity for an efficient preparedness and recovery process, as defined in Table 3.

Table 3 ■ Emergency preparedness and system recovery adaptation strategies

Adaptation Strategy	Measures
Strengthen staff skills for streamlined emergency response.	• Use technology to increase the efficiency of emergency response work crews. • Review the Learning Center courses to ensure that crews are developing the skills required for emergency response. • Incorporate supply shortages into emergency planning exercises.
Plan for resilient and efficient supply chains.	• Develop a resilience checklist for resilient sourcing. • Have a plan already in place for selection and procurement of assets designed to be more resilient in the future. • Ensure that parts inventories are housed out of harm's way and in structures that can survive extreme weather events. • Standardize equipment parts, where possible.
Coordinate extreme event preparedness plans with external stakeholders.	• Continue coordination with telecommunication providers, including through joint emergency response drills. • Continue and strengthen collaboration with the city to improve citywide design, maintenance, and hardening of the stormwater system. For example, improved drainage could alleviate the potential impacts of flooding and increase the effectiveness of adaptation measures in which Con Edison invests (e.g., drain hardening at manholes).
Incorporate low probability events into long-term plans.	• Continue expanding the Enterprise Risk Management framework to include lower probability extreme weather events and long-term issues (e.g., 20+ years). • Conduct additional extreme weather tabletop exercises informed by the future narratives outlined in this report, and consecutive extreme weather events. • Consider expanding the definition of critical facilities and sensitive customers.
Track weather-related expenditures.	• Con Edison's Work Expenditures Group could track expenditures, such as the cost of outages and repairs or customer service calls. Concurrently tracking climate and cost data will enable Con Edison to perform correlation analysis over time.

Update extreme event planning tools.	• Con Edison currently uses an internal Storm Surge Calculator (an Excel workbook that determines the flood measures to be employed for coastal assets based on a given storm tide level) to help plan for coastal flooding impacts. Con Edison could adjust inputs to this program to reflect the following:
	  – Updated storm surge projection information, using high-end forecasted surge
	  – Information from coastal monitoring, such as sea level rise and coastal flooding
	• In addition, Con Edison could regularly revisit the definition of critical equipment so that the Storm Surge Calculator can best inform prioritization of equipment upgrades.

Expand extreme heat worker safety protocols.	• Implement safety protocols (e.g., shift modifications and hydration breaks) practiced in mutual aid work in hotter locations such as Florida and Puerto Rico. • Examine and report on the levels of workers necessary to prepare for and recover from extreme climate events.
Improve recovery times through system and technology upgrades.	• Consider the use of drones and other technology (satellite subscription) or social media apps for damage assessment. • Use GIS system to facilitate locating and documenting damage. • Expand the use of breakaway hardware and detachable service cable and equipment.

Improved Customer Coping

Extreme events can present outsized risks compared to chronic events—risks that, in some cases, also extend to larger geographic areas. For example, impacts from hurricanes can overwhelm multiple facets of Con Edison's system and surrounding communities. Con Edison is positioned at the center of increasingly interconnected societal, technological, and financial systems, making it difficult and inefficient to evaluate risks solely on a component-by-component basis (Linkov, Anklam, Collier, DiMase, & Renn, 2014). Together, these factors necessitate different approaches to considering adaptation compared with climate changes for which probabilities are more easily assigned.

While the City of New York has primary responsibility for coordinating resident emergency response efforts, Con Edison can play a role in increased customer coping and resilience. This includes helping customers cope with reduced energy service if an extreme event leads to prolonged outages (e.g., supporting on-site energy storage, access to locations in the community with power, prioritized service restoration for vulnerable areas). Table 4 provides more specific adaptation strategies. Overall, Con Edison could consider expanding the definition of critical facilities and sensitive customers.

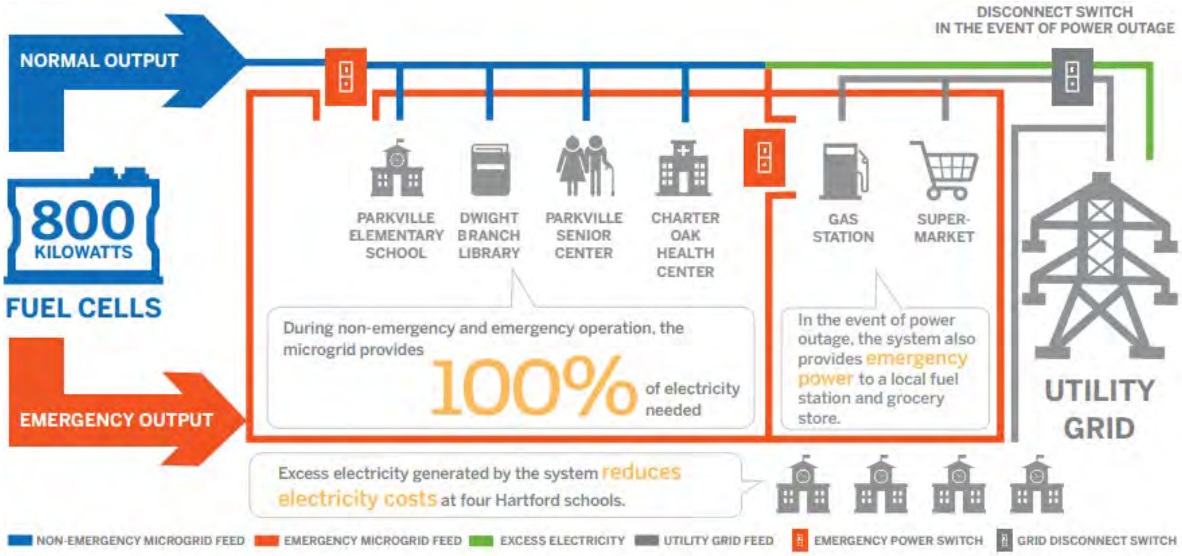
Table 4 ■ Improved customer coping adaptation strategies

Adaptation Strategy	Measures
Create resilience hubs (see below for more information).	• Use solutions such as distributed generation, hardened and dedicated distribution infrastructure, and energy storage so that resilience hubs can function akin to microgrids to provide a range of basic support services for citizens during extreme events. • Continue to promote the pilot resilience hub at the Marcus Garvey Apartments in Brooklyn, using a lithium ion battery system, fuel cell, and rooftop solar to provide back-up power to a building with a community room that has refrigerators and phone charging. • Support additional deployment of hybrid energy generation and storage systems at critical community locations and resilience hubs. • Use AMI capabilities to preserve service for vulnerable populations, if possible.
Invest in energy storage.	• Continue to enhance customer resilience through continued installation of energy storage strategies, including on-site generation at substations or mobile storage on demand/transportable energy storage system (TESS) units, and compressed natural gas tank stations. • Continue to explore ways to help customers install, maintain, and make use of distributed energy resource assets for power back-up, self-sufficiency, and resilience purposes.
On-site generation	• Con Edison currently supports on-site generation for customers through programs such as rebate and performance incentives for on-site residential and commercial photovoltaic solar generation, incentives for behind-the-meter wind turbines, and incentives for combined heat and power projects that Con Edison currently facilitates in collaboration with the New York State Energy Research and Development Authority. • On-site generation is a recommended approach for locations where resilience hubs may not be affordable or necessary. • Con Edison could continue to encourage on-site generation for individual businesses and residential buildings.
Energy efficiency	• Support improved passive survivability, or the ability to shelter in place for longer periods of time, through enhanced energy efficiency programs. • Continue to support energy efficiency programs and further expand its energy efficiency program portfolio to include additional incentives for energy-efficient building envelope upgrades.

Resilience hubs are an emerging idea in resilience planning, which focus on building community resilience by creating a space (or spaces) to support residents and coordinate resources before, during, and after extreme weather events (Baja, 2018). A key requirement for a resilience hub is continued access to energy services. The objective of a resilience hub is to be able to provide a range of basic support services for citizens during extreme events. To accomplish this, resilience hubs may require a hybrid energy solution that includes multiple generation sources (e.g., solar and natural gas generation) and energy storage (i.e., batteries), plus dispatching controls, similar to the functionality of a microgrid. Figure 15 and Figure 16 demonstrate how a fuel cell-based microgrid can be used to power key community locations during normal operating conditions and during emergency events.

Figure 15 ■ Fuel cell-based microgrid supplying energy to key community locations (Constellation Energy)

Figure 16 ■ Diagram of microgrid operations during normal and emergency operations (Constellation Energy)



Electric System

Electric System Overview

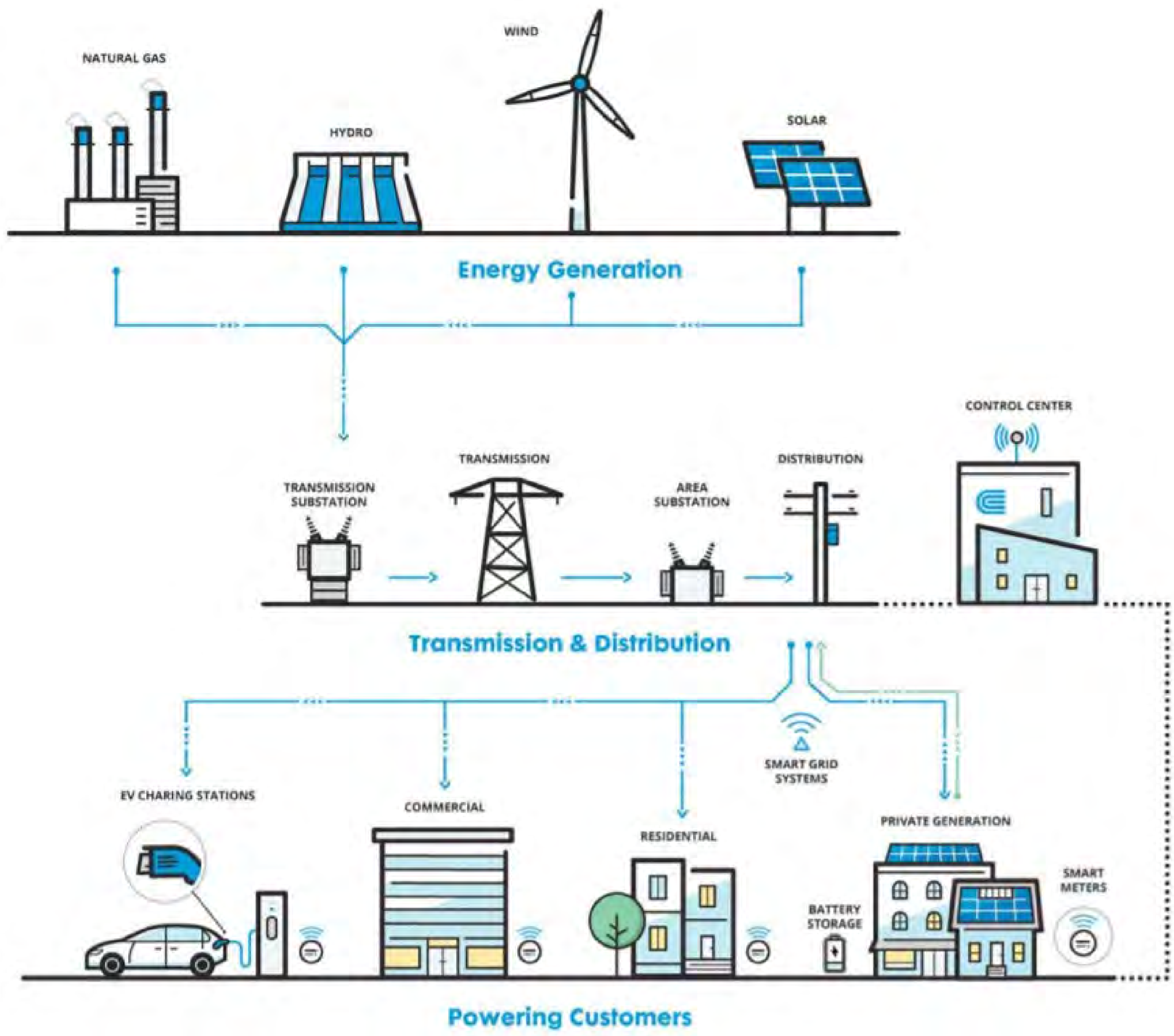
Con Edison's electric service territory includes both New York City and Westchester County, covering an area of 660 square miles and serving 3.3 million customers. Figure 17 depicts a schematic of the Con Edison electric system.

Con Edison's grid is a delivery system that connects energy sources to customers. While most electricity delivered is produced by large third-party generating stations, distributed energy resources also supply energy to the grid.

Energy produced by generating sources is delivered via the Con Edison transmission system, which includes 430 circuit-miles of overhead transmission lines and the largest underground transmission system in the United States, with 749 circuit-miles of underground cable. The system also includes 39 transmission substations. The high-voltage transmission lines bring power from generating facilities to transmission substations, which supply area substations, where the voltage is stepped down to distribution levels.

Con Edison has two different electric distribution systems—the non-network (primarily overhead) system and the network (primarily underground) system. The network system is segmented into independent geographical and electrical grids supplied by primary feeders at 13 kilovolts (kV) or 27 kV. The non-network system is designed using either overhead autoloops with redundant sources of supply, or 4-kV overhead grids arranged in a network configuration or as underground residential distribution systems designed in loop configurations.

Figure 17 ■ Diagram of the Con Edison Electric System



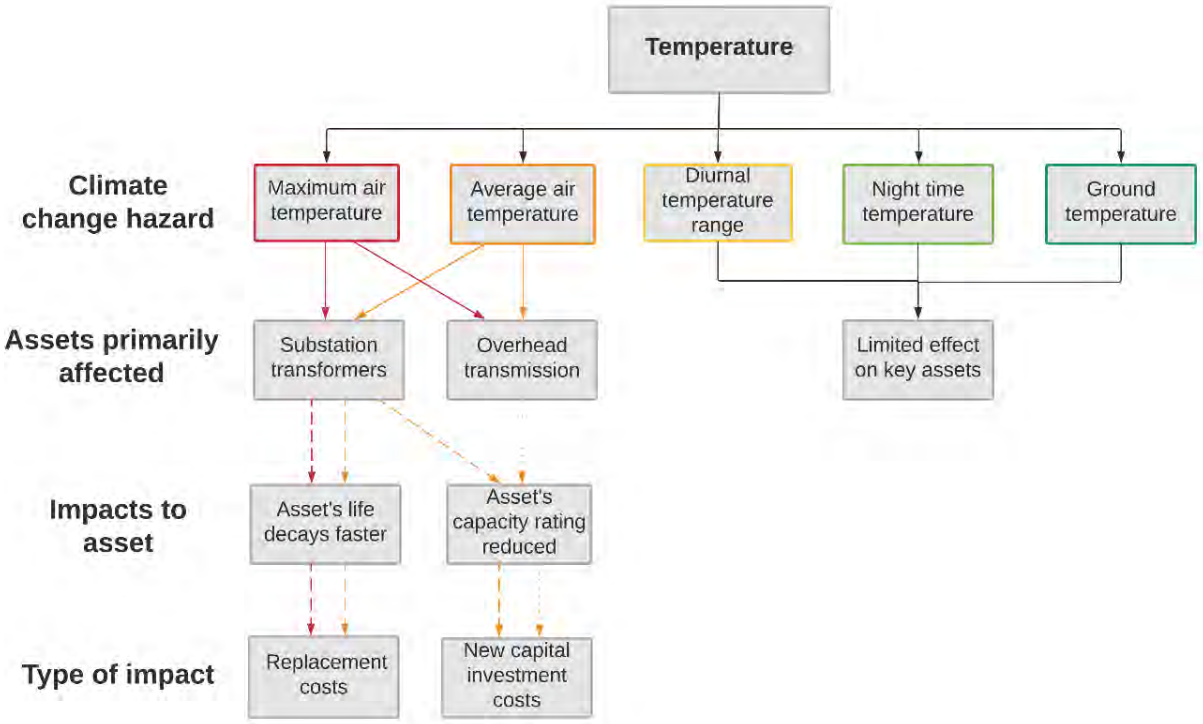
Electric Vulnerabilities

Assets in the electric segment of Con Edison's business are most vulnerable to climate-induced changes in temperature/humidity and sea level rise. Both climate hazards have already shown their ability to bring about outages or damage assets and interrupt operations and carry the potential for future impacts. More information on specific vulnerabilities for these and other climate stressors is discussed below.

Heat and Temperature Variable (TV)

The core electric vulnerabilities for increasing temperature and TV include increased asset deterioration, decreased asset capacity, decreased system reliability, and increased load. Figure 18 illustrates how temperature-related stressors, such as maximum and average air temperature, lead to impacts on the electric system.

Figure 18 ■ Temperature-related impacts on Con Edison's electric system



Increased Asset Deterioration

Increased average temperatures pose a threat to substation transformers. Within a substation, transformers are the asset most likely to be affected by projected higher temperatures since their ambient temperature design reference temperature is lower (i.e., 86°F) than that of most other assets.[13] Higher average and maximum ambient temperatures increase the aging rate of the insulation in transformers, resulting in decreased asset life.[14]

Decreased Asset Capacity

Because an asset's internal temperature is the result of the ambient temperature in which it operates, as well as the amount of power it delivers, operating in an ambient temperature above the design reference temperature decreases the operational rating of the asset. However, derating the system due to increasing temperatures would effectively decrease the capacity of the system. When the capacity of the system is decreased, Con Edison must make investments to replace that capacity. The Con Edison system is currently designed with the capacity to meet a peak summer demand of more than 13,300 megawatts (MW). Based on projected temperature increases, capacity reductions in 2050 could range from 285 MW

[13] Buses, disconnect switches, circuit breakers, and cables all have a design reference temperature of 104°F or higher.
[14] Not every excursion above the designed-for temperature will result in decreased service life. Two conditions must be met for the useful life of the transformer insulation to experience an increased rate of decay: (1) the ambient reference temperature rating must be exceeded, and (2) the transformer must be operating at the rated load, typically as a result of the network experiencing a single or double contingency.

to 693 MW for overhead transmission, switching stations, area station and sub-transmission, and network transformers.[15] This could potentially result in a capital cost of $237 million to $510 million by 2050.

The primary impact of increases in ambient temperatures on overhead transmission lines (assuming peak load) is increased line sag. Insufficient line clearance presents a safety risk should standard measures such as vegetation management not alleviate the risk. If standard measures cannot be applied, the lines would have to be derated and investments would be needed to replace the diminished capabilities of the line.

Decreased System Reliability

Increases in TV-related events are expected to affect the electric network and non-network systems by decreasing reliability. Con Edison uses a Network Reliability Index (NRI) model to determine the reliability of the underground distribution networks.[16] Con Edison has set an NRI value of 1 per unit (p.u.) as the threshold over which reliability is considered unacceptable. Currently, there are no networks that exceed this standard.

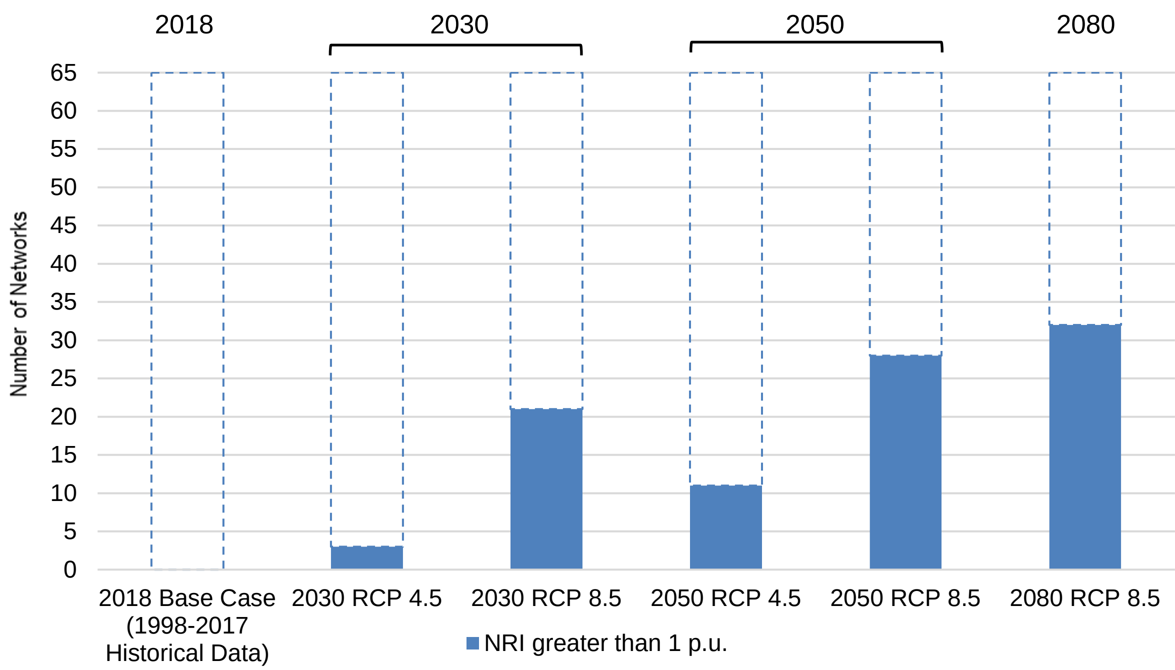
The Study team modeled how the NRI value of each network would change without continued investments in the system. The forward-looking NRI analysis found that with an increase in the frequency and duration of heat waves by mid-century, between 11 and 28 of the networks may not be able to maintain Con Edison's 1 p.u. standard of reliability by 2050, absent adaptation. Under the higher emissions scenario (RCP 8.5 90th percentile), projected impacts are relatively severe, even by 2030, with up to 21 total networks projected to exceed the NRI threshold by that year, absent adaptation (Figure 19). These deficiencies can be reduced by continuing to make investments to better withstand climate events, which Con Edison has done in the past through measures such as infrastructure hardening and added redundancy, diversity, and flexibility in power delivery. Such measures carry the co-benefit of improving blue-sky functionality and reliability.

Currently, Con Edison replaces paper-insulated, lead-covered (PILC) cables as an effective first line of defense against NRI increases. Con Edison is committed to continued investment in this measure, which will help reduce this heat-related vulnerability in the near term. The Study team also quantified the value of other measures to maintain network reliability, including innovative distribution designs and the use of distributed resources, which can be part of microgrids.

[15] The assumed decrease in capacity is 0.7% per °C (0.38% per °F) for substation power transformers, and 1.5% per °C (0.8% per °F) for overhead transmission conductors (Sathaye, 2013).

[16] NRI is a Monte Carlo simulation used to predict the performance of a network during a heat wave. The program uses the historical failure rates of the various components/equipment that are in the network, and through probability analysis determines which networks are more likely to experience a shutdown.

Figure 19 The number of networks above the NRI threshold of 1 p.u. under both climate scenarios for 2030, 2050, and 2080



The Study team also analyzed the impact of climate change on non-network reliability, which is measured in terms of the System Average Interruption Frequency Index (SAIFI).[17] The results indicate that the reliability of the non-network system is somewhat vulnerable to heat events; however, climate impacts would be negligible out to 2080. The average contribution to reliability from non-network autoloop feeder failures and 4-kV grid supply feeder failures due to increased temperatures would only contribute up to 8% of the maximum threshold SAIFI of 0.45 (i.e., a 0.035 increase in SAIFI in 2080) (New York Department of Public Service, 2018).

Increased System Load

When temperature and humidity increase, demand for electricity for cooling also increases. Therefore, higher TV in the summer can cause higher peak loads. The Study team found an increase in peak load in 2050 of 6.9% to 19.2%, as compared to historical conditions. These projected changes in load are due only to the impact of changing TV, and do not take into consideration changes in other factors (e.g., population, increased air conditioning penetration). The Study team found a decrease in winter peak electric load.

Increases in load may require investments in system capacity to meet the higher demand. This cost could be between $1.1 billion and $3.1 billion by 2050. The 10- and 20-year load relief investment plans use asset ratings and load forecasts as key inputs, both of which include temperature as a factor. This combination of a greater demand and a decreased capacity to fill that need will likely warrant a revision to the load relief planning process in the future (Table 5).

[17] SAIFI is a measure of customer reliability. It is the average number of times that a customer is interrupted for 5 minutes or more over the course of 1 year.

Table 5 The combined impacts of increased load and asset capacity reduction in 2050

Scenario	Total capacity under base and future temperature conditions (MW)	Incremental capacity reduction due to temperature	Peak load during current and future 1-in-3 events (MW)	Incremental load increase due to changes in TV	Total additional capacity needed under climate scenarios (MW)
Base Case 2050	13,300	0	13,525	–	0
RCP 4.5 10th percentile 2050	13,015	285	14,949	1,424	1,709
RCP 8.5 90th percentile 2050	12,607	693	16,491	2,966	3,659

Secondary Vulnerabilities

The Study team identified additional heat and humidity-related vulnerabilities in Con Edison's system that were not flagged as priority vulnerabilities but nonetheless present risks.

- **Transmission system:** Con Edison's current transmission system is designed for the highest anticipated loads based on historical values. The Study team found that while load exceeded 90% of the peak load (presenting the possibility for thermal overload) on 1.5% of summer days historically, by 2050, this may increase to 5.2% of days under the RCP 8.5 90th percentile scenario. This shift in TV distribution may result in a small increase in the frequency of load drop from the transmission system.
- **Summer operations and voltage reductions:** When summer temperatures soar, Con Edison implements a set of procedures to avoid voltage and thermal stresses on the system. These procedures are triggered by a threshold (e.g., TV 86, which is the 1-in-3 peak load-producing TV). The Study team found that there could be a significant increase in the number of days with voltage reductions and summer work restrictions. However, if Con Edison continues to invest in the system to ensure operational capacity during the 2050 1-in-3 TV event, then there will be a drop in the frequency of voltage reductions and summer work restrictions, relative to today.
- **Corporate Emergency Response Plan:** Con Edison also uses TV thresholds to trigger elevated threat levels under its Corporate Emergency Response Plan (CERP). The Study team conducted an analysis to understand how the projected changes in TV will affect the exceedance of current CERP threat levels. The analysis indicates that TV conditions exceeding current thresholds will increase in both the lower (RCP 4.5 10th percentile) and higher (RCP 8.5 90th percentile) climate change scenario. The conditions for reaching a "Serious" threat level based on the current thresholds, for example, would increase from 0.4 days per summer, on average, to 1.8 days under RCP 4.5, and 12.8 days under RCP 8.5.
- **Volume forecasting:** Con Edison conducts volume forecasting to estimate the volume of energy the company needs to purchase, a portion of which is weather-sensitive. The calculation for this portion relies primarily on heating degree-days (HDDs) for the winter and cooling degree-days (CDDs) for the summer. The Study team estimated that Con Edison could experience an increase in summertime CDDs, which could result in the energy delivery increasing from 43,077 gigawatt-hours (GWh) in 2050 under the base case to 43,685 GWh under the RCP 4.5 scenario (a 1.4% increase), and to 45,394 GWh under the RCP 8.5 scenario (a 5.4% increase). The Study team found a less significant decrease in HDDs due to climate change.

Sea Level Rise

RCP 4.5 and RCP 8.5 projections indicate that sea level rise may exceed Con Edison's current design standard for coastal flood protection (i.e., a 100-year storm with 1 foot of sea level rise and 2 feet of freeboard) between 2030 and 2080. The Study team analyzed the exposure of Con Edison's assets to 3 feet of sea level rise (i.e., the 2080 RCP 8.5 83rd percentile sea level rise projection), keeping the other elements of Con Edison's existing risk tolerance constant (i.e., a 100-year storm with 2 feet of freeboard). By summing the freeboard and sea level rise values, this equates to FEMA's 100-year floodplain elevation plus 5 additional feet.

Of the 324 electric substations (encompassing generating stations, area substations, transmission stations, unit substations, and Public Utility Regulating Stations [PURS]), 75 would be vulnerable to flooding during a 100-year storm if sea level rose 3 feet. Three of these potentially exposed substations would only require minimal modifications to protect them, 16 would require an extension of existing protections, eight would require a new protection approach (i.e., the existing protections cannot be extended), and 48 do not have existing protections because they are outside of the floodplain. Hardening all these substations is estimated to cost $636 million.

Precipitation

The Study team found that substations, overhead distribution, underground distribution, and the transmission system are most at risk for precipitation-based hazards.

Substations may experience an overflow of water from transformer spill moats, which could release oil-contaminated water within the substation. However, the risk of such an event is low, as transformer spill moats are built at a level that is robust to all but a severe and highly improbably conjunction of events.[18]

The transmission and overhead distribution systems are both vulnerable to the accumulation of radial ice, which can build up on lines and towers during winter precipitation events. In extreme scenarios, accumulation of radial ice can result in unbalanced structural loading and subsequent transmission line failure, especially when accompanied by heavy winds (Nasim Rezaei, Chouinard, Legeron, & Langlois, 2015). Con Edison's current system meets the National Electrical Safety Code standard for radial ice and is robust to ice accumulation. It is uncertain whether climate change will increase or decrease the intensity of future icing events.

The underground distribution system is vulnerable to flooding and salt runoff from snowfall and ice events. Flooding can damage non-submersible electrical equipment. This risk is mitigated through Con Edison's designs: All underground cables and splices operate while submerged in water, and all underground distribution equipment installed in current flood zones (and all new installations) are submersible. Snowfall and ice require municipalities to spread salt on roads, which eventually seeps into the ground with runoff water. Road salt can degrade wire insulation and lead to insulation burning and arcing, potentially causing safety concerns and customer outages. It is currently unclear how salting frequency will change over time.

Extreme Events

Hurricanes and nor'easters present physical risks associated with heavy winds, precipitation, and flooding, which can lead to widespread system outages and, at worst, physical destruction. During hurricanes, wind stress and windblown debris can lead to tower and/or line failure of the overhead transmission system

[18] In accordance with New York State code and federal Spill Prevention, Control, and Countermeasure recommendations, Con Edison's transformers are protected by moats designed to hold water from a 6-inch, 1-day storm event, in addition to the gallons of oil that may be released during a spill event and a further 50,000–60,000 gallons of fire suppression fluid. Based on this standard, Con Edison's substation transformer moats are robust to 6 inches of rain during a catastrophic emergency, and significantly more than that at all other times.

and damage overhead distribution infrastructure, which could cause widespread customer outages. Intense rain during hurricanes can also flood substations, which may cause an overflow of oil-contaminated water from transformer spill moats. A Category 4 hurricane could very likely lead to outages for more than 600,000 non-network customers and more than 1.6 million network customers.

During nor'easters, accumulation of radial ice can cause tower or line failure of the overhead transmission system. Similarly, snow, ice, and wind can damage the overhead distribution system. Indirectly, salt put down by the city to contend with snow and ice accumulation on roads could infiltrate the underground distribution system, causing arcing and failure of underground components.

Extreme heat waves present a range of effects that can contribute to failures, including a lower ampacity rating while increasing load demand, causing cables and splices to overheat, transformers to overheat, and transmission and distribution line sag. Distribution network component failures can cause Con Edison to exceed the network reliability design standard. Greater line sag can lead to flashovers and line trips.

Adaptation Options for the Electric System

Withstand

In the short term, Con Edison can work to address the vulnerabilities of the electric system by integrating climate hazard considerations into planning, collecting data on priority hazards, and updating design strategies.

There are several opportunities to integrate climate change data into planning processes. For example, Con Edison could integrate climate change projections into long-term load forecasts, consult utilities in cities with higher temperatures to refine the load forecast equation for high TV numbers, and develop a load relief plan that integrates future changes in temperature and TV into asset capacity and load projections. During load relief planning, Con Edison could also consider whether extreme events may shift the preferred load relief option—frequent extreme heat could reduce the effectiveness of demand response programs. For the transmission system, Con Edison could integrate considerations of climate change into the long-range transmission plan. For the distribution system, Con Edison could integrate climate projections into NRI modeling and install high-reliability components,[19] as needed.

Given the potential risks that temperature and heat waves pose to the electric system, the Study team suggests that Con Edison could collect data on these hazards to build greater awareness of their impacts to the system, as well as to monitor for signposts that would trigger additional action. Specifically, Con Edison could:

[19] System components vary in their reliability. For example, PILC cable performs more poorly than solid dielectric cable.

- Install equipment capable of collecting, tracking, and organizing temperature data at substations to allow for location-specific ratings and operations.
- Make ground temperature data more accessible and track increases over time.
- Expand monitoring and targeting of high-risk vegetation areas.
- Continue to track line sag and areas of vegetation change via light detection and ranging (LiDAR) flyovers to identify new segments that may require adaptation.

These data could be used to routinely review asset ratings in light of observed temperatures. Con Edison could also incorporate heat wave projections into reliability planning for the network system.

Hurricanes are another priority hazard for the electric system and therefore warrant robust planning tools that capture potential changes in climate. Con Edison could complement their existing model used to predict work crews required to service weather-driven outages with an updated model that better resolves extreme weather events and extreme weather impacts on customers in the service territory.

Design standards are a way to help standardize resilience by ensuring that new assets are built to withstand the impacts of climate change hazards. The Study team suggests a variety of design standards:

- **Temperature:** Standardize ambient reference temperatures across all assets for development ratings.
- **Precipitation:** Update precipitation design standards to reference National Oceanic and Atmospheric Administration (NOAA) Atlas 14 for up-to-date precipitation data. Consider updating the design storm from the 25-year precipitation event to the 50-year event to account for future increases in heavy rain events.
- **Sea Level Rise:** Revise design guidelines to consider sea level rise projections and facility useful life. Continue to build to the higher of the FEMA + 3′ level and the Category 2 storm surge levels at new-build sites, as is current practice. Add sea level rise to the Category 2 maps to account for future changes and a greater flood height/frequency.

In addition to these systematic approaches, Con Edison can also help the electric system better withstand climate hazards through asset-specific physical adaptation measures, when needed. Table 6 illustrates these physical options.

Table 6 Potential physical adaptation options for electric assets

Main Hazard(s)	Vulnerable Assets or Plan	Adaptation Option	Implementation Timeframe	Signpost or Threshold
Temperature	Grid modernization	Continue to invest in grid modernization to increase resilience to climate change through new technology and increased data acquisition. Efforts include distribution automation, grid-edge sensing (environmental, AMI), asset health monitoring, conservation voltage optimization, and targeted system upgrades.	Continuous	Change in ambient operating temperatures, including changes in science-based projections
Heat Waves	Network system, which may experience reduced reliability (and therefore increased NRI) due to heat waves	Complete PILC cable replacements.	2030	Increased frequency or duration of heatwaves
		Continue implementing load relief strategies to keep NRI ratings below 1. Options include: • Split the network into two smaller networks. • Create primary feeder loops within and between networks. • Install a distribution substation. • Incorporate distributed energy resources and non-wire solutions. • Design complex networks that consider combinations of adaptation measures.	Continuous	NRI value over 1 p.u.
	Non-network distribution system	Maintain non-network reliability in higher temperatures by implementing the following: • Autoloop sectionalizing • Increased feeder diversity	2080	Forecasted System Average Interruption Frequency Index (SAIFI) ratings (incorporating climate change projections) above established thresholds
	Overhead transmission	Replace limiting wire sections with higher rated wire to reduce overhead transmission line sag during extreme heat wave events. Alternatively, remove obstacles or raise towers to reduce line sag issues.	Continuous	Increased incidence of line sag; higher operating temperatures
		Explore incorporating higher temperature-rated conductors.	2050	Existing asset replacement
	Area and transmission substation transformers	Undertake measures that contribute to load relief, such as energy efficiency, demand response, adding capacitor banks, or upgrading limiting components, such as circuit breakers, or disconnect switches and buses.	2030/2050	Ambient temperatures exceeding asset specifications
		Gradually install transformer cooling, or replace existing limiting transformers within substations.	2050/2080	Ambient temperatures exceeding asset specifications
Precipitation	Substations	Harden electric substations from an increased incidence of heavy rain events by doing the following: • Raising the height of transformer moats • Installing additional oil-water separator capacity • Increasing “trash pumps” behind flood walls to pump water out of substations	2080	Changes in the 25-year return period storm
	Transmission and overhead distribution	Underground critical transmission and distribution lines.	2080	Increased incidence of icing

Main Hazard(s)	Vulnerable Assets or Plan	Adaptation Option	Implementation Timeframe	Signpost or Threshold
	Underground distribution	Retrofit ventilated equipment with submersible equipment to eliminate the risk of damage from water intrusion.	2050	Expanded area of precipitation-based flooding; better maps of areas at risk for current and future precipitation-based flooding
		Reduce the incidence of manhole events due to increased precipitation and salting by doing the following: • Expanding Con Edison's underground secondary reliability program • Accelerated deployment of vented manhole covers • Replacement of underground cable with dual-layered and insulated cable, which is more resistant to damage • Installation of sensors in manholes to detect conditions indicating a potential manhole event	2050	Increase in the City's use of salt over the winter period; increased rate of winter precipitation
Hurricanes	Overhead transmission	Continue to expand existing programs to reinforce transmission structures; address problems with known components.	Continuous	Increased frequency/severity of heavy winds; existing asset replacement
	Overhead distribution	Invest in retrofits for open wire design with aerial cable and stronger poles.	2080	Increased frequency/severity of heavy winds; existing asset replacement
		Underground critical sections of the overhead distribution system to ensure resilience against hurricane force winds and storm surge.	2080	Increased frequency/severity of heavy winds
Nor'easters	Overhead transmission and distribution	Continue to expand programs to reinforce transmission and distribution structures and expand the number of compression fittings used to address weak points in transmission lines.	Continuous	Increased incidence of icing; existing asset replacement
	Underground distribution	Upgrade high failure rate components.	Continuous	Increased frequency/severity of nor'easter events

Of course, it is neither practical nor feasible for Con Edison to build resilience to the point that its electric system can fully withstand the impacts of all climate hazards. The Study team thus suggests that Con Edison consider the following strategies to help the electric system better absorb and recover from impacts:

Absorb

- **Temperature:** Increase capabilities to provide flexible, dynamic, and real-time line ratings.
- **TV:** Routinely update voltage reduction thresholds and hands-off thresholds to account for changes in climate and the changing design of the system.
- **Hurricanes:** Continue to explore and expand operational measures to increase the resiliency of the overhead distribution system by increasing spare pole inventories to replace critical lines that are compromised during extreme weather events.
- **Heat waves:** Stagger demand response consecutive event days across different customer groups to increase participation; ensure that demand response program participants understand the purpose/cause of the event; use technology to more efficiently regulate load/use AMI to rapidly shed

load on a targeted network to help ensure that demand does not exceed supply; and continue installation of energy storage strategies, including on-site generation at substations or mobile storage on demand/transportable energy storage system (TESS) units, and compressed natural gas tank stations.

Recover

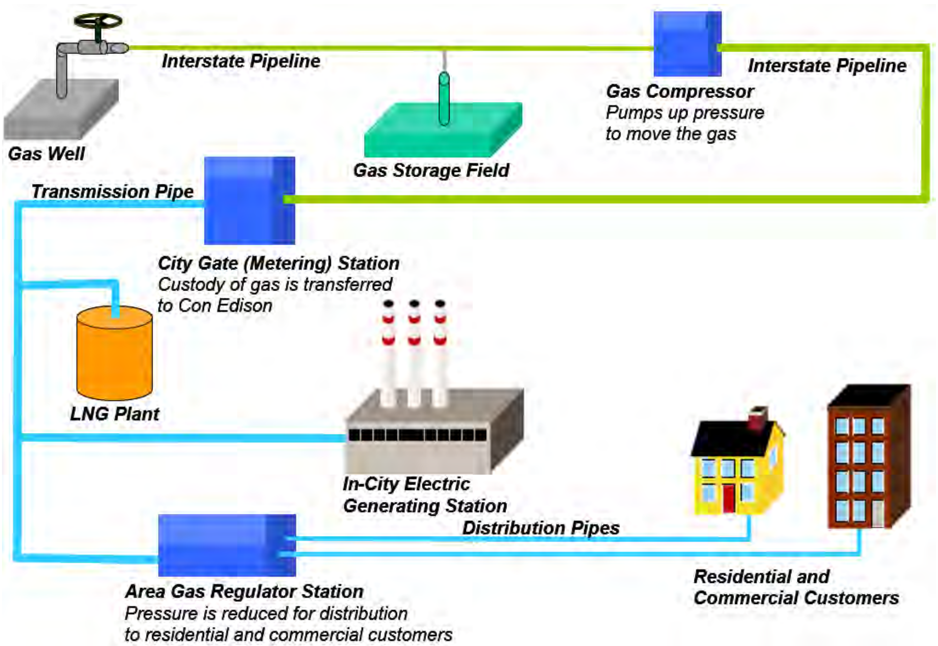
- **Heat waves:** Continue to actively engage forward-looking technologies to improve extreme recovery time for distribution systems, such as automated splicing systems to reduce feeder processing times.
- **Extreme events:** Support additional deployment of hybrid energy generation and storage systems at critical community locations and resilience hubs; support increasing the percentage of solar/other distributed generation projects to allow for islanding; encourage on-site generation for individual businesses and residential buildings; and increase the use of LiDAR and drones to assess damage and reduce manual labor.

Gas System

Gas System Overview

Con Edison's gas service territory covers Manhattan, Bronx, Westchester, and parts of Queens. Con Edison serves approximately 1.1 million firm customers and 900 large-volume interruptible customers who can alternate fuel sources. The natural gas system consists of more than 4,359 miles of pipe transporting approximately 300 million dekatherms (MMdt) of natural gas annually. About 56% of the system operates at low pressure, 11% operates at medium pressure, and 33% operates at high pressure. Figure 20 depicts the Con Edison natural gas delivery chain.

Figure 20 ■ Con Edison natural gas delivery chain



Gas Vulnerabilities

Most of Con Edison's gas assets are underground, and gas load peaks in the winter rather than in the summer, which means that gas assets are less likely to be damaged by subaerial extreme events, such as heat waves, lightning, and strong winds. As discussed in Con Edison's Post Sandy Enhancement Plan, Con Edison's gas assets are most vulnerable to underground water intrusion caused by flooding, and thus projected increases in the frequency of heavy precipitation and downpours, sea level rise and storm surge, and hurricanes and nor'easters pose a significant risk (Con Edison, 2013).

Water intrusion can occur if underground water enters gas pipes or mains and may result in a drop in pressure and lead to scattered service interruptions; low-pressure segments of the system and cast iron pipes are particularly vulnerable to this risk. In addition, pipe sections near open-pit construction projects may also be more vulnerable, because open excavation work can create opportunities for water intrusion if flood protection measures are not consistently used. Con Edison has already developed operational protocols that require crews working on open excavation sites to secure them to minimize water intrusion risk.

Water intrusion into gas regulators through aboveground vents may also cause damage. This intrusion could lead to water sitting on top of the diaphragm that allows each regulator to function and exerting additional pressure on the diaphragm that could, in turn, over-pressurize the regulator. Over-pressurized gas flowing through a system designed for lower pressure gas increases the possibility of tearing leaks in distribution piping, and in the worst-case scenario, could blow out pilot lights.

For the gas distribution system to function at full capacity and to be able to provide customers with desired gas supply, Con Edison must keep gas moving through the system at the intended flow rate, or pressure level, of each system segment. Once water enters the gas system, it is difficult to pinpoint the location and remove the water, which can increase the durations of resulting service interruptions.

Con Edison is currently undertaking several measures to manage underground water intrusion:

- Using drip pots to collect water at low points in the system (approximately 8,000 are currently in place)
- Developing a program to better prioritize gas infrastructure replacements. Remote sensors and machine learning could identify leak-prone areas to prioritize for upgrades intended to mitigate increasing precipitation risks in the face of climate change
- Developing a drip pot remote monitoring program using sensors, which would increase the efficiency of periodic emptying of drip pots and reduce the effort needed to monitor drip pots during the period of planned pipe replacement
- Shifting toward constructing and repairing infrastructure with more leak-resistant equipment, when possible

A climate change-driven increase in the frequency and intensity of flood events, such as heavy rain events or snow events followed by rapid snow melt, or coastal storm surge, may elevate the risk of water infiltration into the low-pressure gas system. The precipitation threshold currently used as a benchmark for monitoring and emptying drip pots is ½ inch of rain in 24 hours. Under the RCP 8.5 scenario, this threshold is projected to be exceeded 37 days per year in Central Park by the latter part of the century, which is nearly 20% more than the 31 days observed over the baseline period.

Low-probability, high-impact extreme events may also include heavy rainfall and storm surge that could increase the risk of water entering the distribution system. An increase in the frequency and intensity of extreme events may make water infiltration into the gas distribution system more likely. Con Edison's gas system has established criteria to ensure that new equipment, such as gas regulator line vents, is resilient against a 100-year storm and 1 foot of sea level rise. After Superstorm Sandy, Con Edison upgraded two regulator stations to meet this standard. The Study team determined that to protect regulator stations against 3 feet of sea level rise, Con Edison would need to update 32 regulator stations, at a cost of $13.8 million.

The gas transmission system is vulnerable to cold snaps associated with nor'easters, when temperatures can drop below 0°F for multiple days. Transmission system capacity is designed to meet demand projected for weather conditions at or above 0°F. Temperatures below that threshold may increase demand to a level that exceeds system capacity; in such an event, system pressure may decrease, resulting in customer service loss.

In a generally warmer climate, the gas sector could experience significant decreases in winter energy sales for heating. There could be up to a 33% decrease by 2050 and a 49% decrease by 2080. Similarly, under the RCP 8.5 scenario, winter gas peak load is projected to decrease by 144 MMdt in 2050, compared to the base case.

Adaptation Options for the Gas System

In addition to Con Edison's existing efforts, the Study team identified several additional adaptation options that the company could consider. Some measures proposed, such as remote information monitoring and analysis, address vulnerabilities in operations and planning processes. Most measures proposed address physical vulnerabilities (see Table 7), which fall within the "withstand" adaptation category.

In the short term, Con Edison could focus on expanding its monitoring capabilities, particularly through programs that use machine learning and remote monitoring to identify vulnerable areas of the distribution system, and remote drip pot monitoring sensors.

To account for changing temperatures, Con Edison could integrate climate change data on changes in the winter gas TV into gas volume and peak load forecasting so that the company is continuously planning for future changes in climate.

To address physical risks to existing infrastructure, Con Edison may need to invest in the system at strategic points in time, as described in Table 7.

Distribution system measures focus on minimizing the risk of flood water entering and depressurizing gas mains and pipes, and measures to more easily re-elevate pressure if water does enter the system.

Adaptation measures identified to address transmission system vulnerabilities primarily focus on diversifying the system and strengthening load management when capacity is constrained.

Table 7 ■ Physical adaptation options for gas commodities

Hazard	Asset	Adaptation Option	Implementation Timeframe	Signpost or Threshold
Extreme Hurricane (Category 4)	Transmission System	Procure additional compressed natural gas tank stations.	Designing for a future Category 4 hurricane	Increased frequency and severity of storms that could cut supply, including from science-based projections
	Gas Regulators	Install vent line protectors, extend vent lines and posts, seal all penetrations, and/or elevate key electric and communications equipment to protect vent lines.	2050	When sea level rise exceeds 1 foot, or if flooding is reported and the regulators do not have vent line protectors
	Distribution System	Continue targeted Main Replacement Program (planned completion by 2036) to harden gas mains against depressurization by water intrusion or other concerns.	~2030 (goal to complete program by 2036)	Increase in flooding events
Extreme Nor'easter	Transmission System	Construct additional gate stations.	Designing for a future worst-case nor'easter	More frequent or intense cold spells that drop temperatures below the design threshold for consecutive days and threaten supply
		Build larger and/or additional transmission mains.		
		Create ties between mains to diversify the transmission system.		
		Install remote operated valves to more efficiently isolate load for load management (temporarily disconnecting gas customers) during peak events.		

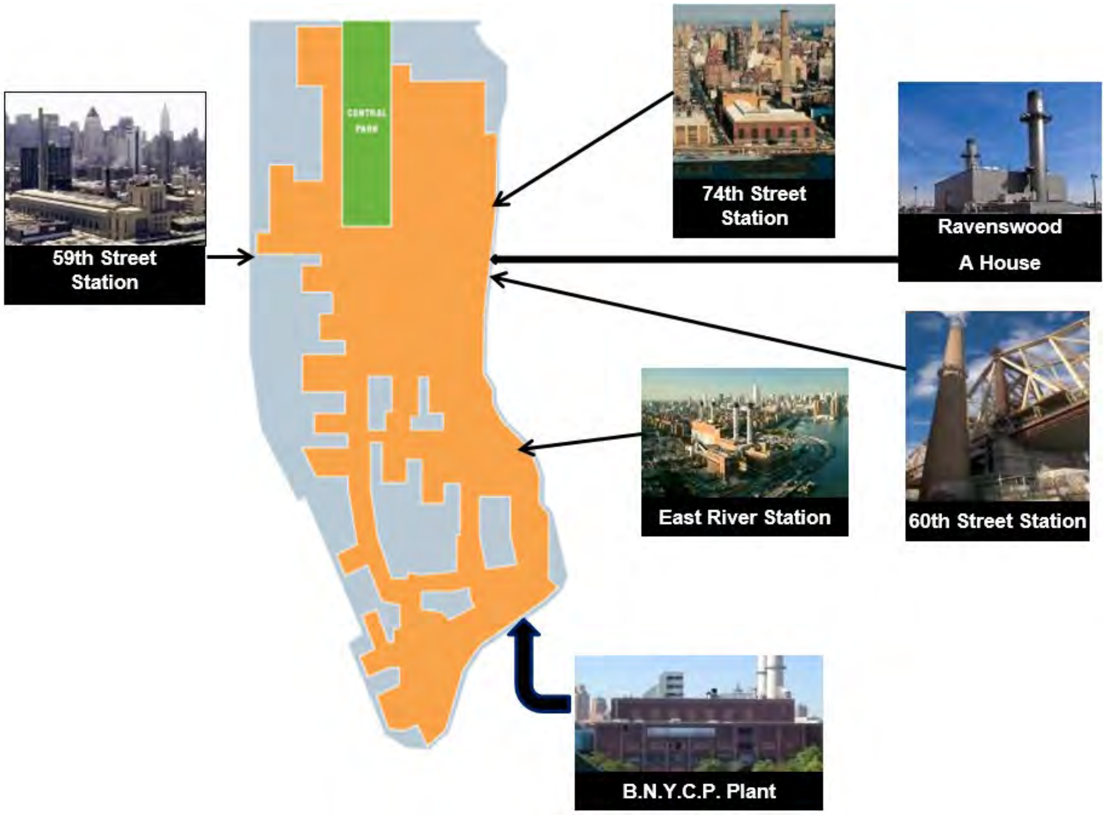
In addition, given the increasing potential for extreme events, Con Edison could consider distribution system resilience options such as exploring and implementing ways to elevate system pressure in low-flow conditions.

Steam System

Steam System Overview

Con Edison's steam system provides service to more than 3 million Manhattan residents (including approximately 1,720 metered customers) south of 96th Street. Total system capacity is about 11,676 thousand pounds per hour (Mlb/hr). The distribution system is comprised of a continuous network of pipes (steel main pipes and steel and brass service and condensate piping)—in aggregate, about 105 miles of piping. The pipes' physical location is directly correlated with the locations of generation sources and regional customer demand. Figure 21 shows the locations of several steam system assets.

Figure 21 ■ Key assets included in the Con Edison steam system



Steam Vulnerabilities

Like the gas system, much of Con Edison's steam system is underground, and steam is also a winter-peaking rather than a summer-peaking commodity. As such, steam generation and distribution assets are generally less prone to damage by shifts and extremes in temperature, humidity, and wind, and more vulnerable to flooding, which may be caused by increased precipitation, coastal inundation, snow melt, or storm surge in extreme events. Severe flooding impacts, such as broken distribution pipes and damaged steam generation stations, can take significant time to repair, further increasing the duration of customer impacts.

Increased frequency and intensity of precipitation events may increase the vulnerability of steam system manholes to "water hammer" events. When a high volume of water collects around a manhole, steam in the pipes underneath may cool and condense. Interaction between steam and the built-up condensate may cause a rupture in a steam pipe. One such water hammer event occurred in 2007 when a steam pipe at Lexington Avenue and 41st Street exploded during a period of heavy rainfall (Figure 22). Con Edison responded to that event by implementing a precautionary rain event threshold. If more than ¾ inch of rain is forecasted to fall within 3 hours, Con Edison will begin to proactively monitor and address flooding before it can cause a water hammer event. The key measure used to address flooding to prevent water hammer events is pumping water out of manholes and into the city sewer. In turn, Con Edison's capacity to manage flooding events that threaten steam generation and distribution assets depends on the capacity of the city's stormwater system to handle high volumes of water that Con Edison may need to pump away from assets under a changing climate.

Steam generation and distribution system assets are also vulnerable to projected increases in sea level and coastal inundation. Five out of six steam generating plants would be exposed to a 100-year storm if sea level rose by 3 feet. If water enters the steam generation system, it can degrade plant capacity or force unit or plant outages. Significant damage to steam generation systems would likely require long repair times, which could increase the duration of customer impacts. Hardening several of the generating stations to a higher level of protection would be difficult and costly. For example, at the East River Generating Station, raising mechanical equipment would require significant and costly alterations to the hydraulics of the steam system. Similarly, at East 13th Street, flood waters associated with a 100-year storm and 3 feet of sea level rise would reach the tertiary bushings on some 345-kV transformers, resulting in arcing and critical failure of the unit. The total estimated cost to harden the five steam generation plants against a 100-year storm and 3 feet of sea level rise is $30 million.

Figure 22 ■ 2007 steam pipe explosion

Con Edison has adopted storm hardening measures to protect the steam system in response to recent storms such as Superstorm Sandy. Those measures include developing location-specific plans and drills in preparation for storms, implementing physical hardening measures at steam generating stations, protecting critical equipment by waterproofing or relocating it, installing a new steam main to ensure that hospitals receive continued service, and introducing isolation valves in strategic locations to reduce the number of customers impacted by flooding in future extreme events. Because isolating steam lines is key to managing flooding impacts, Con Edison considers several potential flood sources (e.g., rainfall deluges, storm tides, water main breaks) when evaluating hardening options, and periodically reviews and updates both operational and physical risk mitigation strategies. The company is also investing in steam system resilience through measures such as waterproofing system components in the normal course of upgrades, prioritizing hardening steam mains by prior flooding issues (fewer than 10 of the original 86 locations identified are still vulnerable), and using remote monitoring to monitor manhole water level and steam trap operation (a system is currently under design and expected to be operational by 2021).

Extreme and multi-hazard events could also increase the vulnerability of the steam distribution system to salt damage and flood damage. During nor'easters and extreme ice storms, the City of New York and jurisdictions in Westchester County conduct widespread street-salting operations to mitigate ice build-up on roads and sidewalks. Rapid melt after nor'easters and extreme ice storms can lead to an influx of salt-saturated runoff into manholes, in turn causing equipment degradation and, in some cases, manhole fires or explosions.

In a generally warmer climate, the steam system could experience significant decreases in winter energy sales for heating. There could be up to a 33% decrease by 2050 and a 49% decrease by

2080. Similarly, under the RCP 8.5 scenario, winter gas peak load is projected to decrease by 891 Mlb/hr in the winter of 2050 compared to the base case.

Adaptation Options for the Steam System

To determine when to implement various adaptation strategies, Con Edison could track climate trends, including TV, precipitation, sea level rise and storm surge, and extreme events, as described in prior vulnerability and adaptation sections.

The Study team suggests that Con Edison could continue to work collaboratively with other city actors on initiatives that could help strengthen the resilience of the steam system. Specifically, the company could take measures, including the following:

- Strengthen collaboration with the city to improve citywide stormwater design to alleviate flooding impacts and make adaptation measures implemented by Con Edison, such as drain pumps at manholes, more effective.
- Discuss ways to minimize salt use during the winter.
- Incorporate considerations of New York City initiatives in coastal resiliency plans for lower Manhattan to re-evaluate Con Edison's storm response plans and stages of pre-emptive main shutoffs.

In addition to engaging in these monitoring and coordination efforts, the company could also consider taking measures to address physical vulnerabilities in existing infrastructure by strategically investing in the system. Physical measures developed by the Study team are listed in Table 8.

Table 8 ■ Physical adaptation options for steam commodities

Hazard	Asset	Adaptation Option	Implementation Timeframe	Signpost or Threshold
Extreme Hurricane (e.g., Category 4)	Generation System	Invest in additional storm hardening investment measures to protect generation sites against extreme hurricane-driven storm surge. Leverage new innovations and advancements in flood protection over time and raise moated walls around current generation sites.	2050	When sea level rise exceeds 1 foot
	Distribution System	Continue to segment the steam system to limit customer outages in flood-prone areas.	In preparation for a Category 4 hurricane	Increased frequency and severity of storms, including from science-based projections
	Distribution System	Expand programs to harden steam mains (waterproofing pipes and raising mains).	In preparation for a Category 4 hurricane	Increased frequency and severity of storms, including from science-based projections
		Pre-stage a greater number of drain pumps at critical or flood-prone manholes.		

As it is neither practical nor feasible for Con Edison to build resilience to the point that its steam system can fully withstand the impacts of extreme events, Con Edison could also consider implementing additional strategies to better absorb and recover from impacts, such as improving systems for crowd-sourcing steam system leak detection.

Moving Towards Implementation

Initial Climate Projection Design Pathway

Implementation of adaptation options to mitigate vulnerabilities requires clear climate design guidelines that incorporate forward-looking regional climate change projections. To this end, the Study team suggests that Con Edison could establish an "initial climate projection design pathway" that considers appropriate risk tolerance levels within the range of climate change projections. The initial climate projection design pathway is meant to guide preliminary planning and investments until and if Con Edison can refine the pathway to reflect new climate projections with reduced uncertainties, changes to Con Edison's operating environment, and changes in city guidance. The following section outlines an adaptive management approach that allows Con Edison to monitor, manage, and design to acceptable levels of climate risk through time.

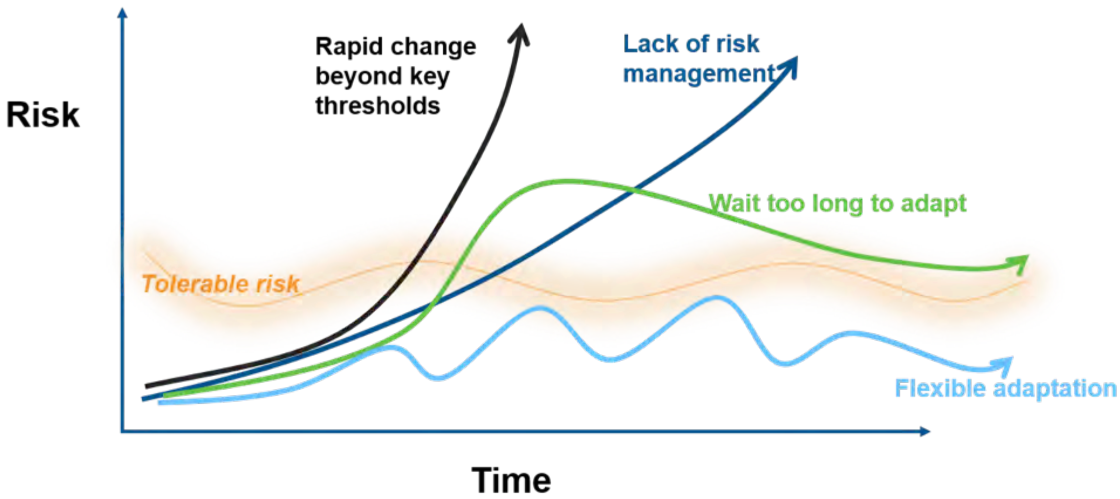
As an initial climate projection design pathway for decisions that require it, Con Edison will follow the conservative precedent set by the city's climate resiliency design standards (e.g., Mayor's Office of Recovery and Resiliency, 2019), combined with the state-of-the-art climate projections produced for this Study. Corresponding to city guidance, the same pathway may not apply uniformly across different climate change projections and hazards. More specifically, multiple climate projection design pathways may be required to address differences in the risk tolerance and projection uncertainty associated with different climate hazards. Under this framework, initial pathways could use the 50th percentile merged RCP 4.5 and 8.5 projections for sea level rise and high-end 90th percentile merged RCP 4.5 and 8.5 projections for heat and precipitation. Climate projection design pathways will be finalized for Con Edison's Climate Change Implementation Plan.

Alternative considerations are necessary to inform pathways for rare and difficult-to-model extreme events without probabilistic projections, such as 1-in-100-year heat waves and strong, multi-faceted hurricanes. Rather than prescribing statements of probability, these types of extremes require the blending of plausible worst-case scenarios from a climate perspective with stakeholder-driven worst-case scenarios from an impact perspective. Until climate modeling can better resolve and simulate these types of rare extreme events, the union of these two perspectives is critical for determining acceptable risk tolerance levels and setting initial pathways.

Flexible Adaptation Pathways Approach

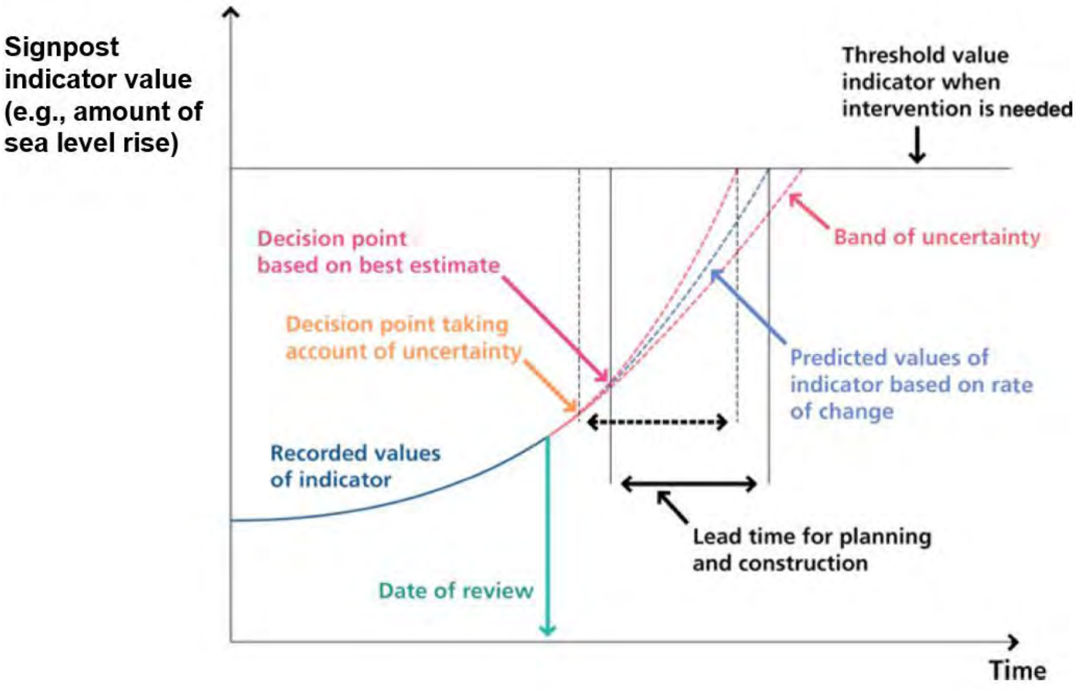
While the initial climate design pathway can inform asset design, a complementary approach is needed to ensure resilience over the lifetime of that asset. A flexible and adaptive approach will allow Con Edison to manage risks from climate change at acceptable levels, despite uncertainties about future conditions. The flexible adaptation pathways approach ensures continued adaptability over time as more information about climate change and external conditions is learned. Figure 23 depicts how flexible adaptation pathways are used to maintain tolerable levels of risk.

Figure 23 ■ Flexible adaptation pathways in the context of tolerable risk and risk management challenges to non-flexible adaptation. Adapted from Rosenzweig & Solecki, 2014.



Con Edison will need to consistently track changing conditions over time to identify when additional adaptation strategies are required. This approach relies on (1) monitoring indicators ("signposts") related to climate conditions, climate impacts, and external conditions that affect system resilience, and (2) pre-determined thresholds to signal the need for a change in risk management approaches ("transformation points"). This approach can support decisions on when, where, and how Con Edison can take action to continue to manage its climate risks at an acceptable level. Figure 24 depicts how a signpost indicator and a predefined threshold can be applied in the adaptation pathways approach to inform the timing of action given uncertainty.

Figure 24 ■ Schematic diagram of how an indicator of change for a particular signpost (e.g., amount of sea level rise) informs decision lead times that take into account uncertainty (Ranger et al., 2012).



Con Edison is already familiar with monitoring signposts to manage planning uncertainties and guide adjustments to its Electric, Gas, and Steam Long Range Plans.[20] Con Edison currently monitors signposts related to the pace of technology innovation (e.g., energy management technologies), the nature of regulation and legislation (e.g., new or revised greenhouse gas reduction policy targets), and the future of the economy (e.g., higher economic growth and impacts on demand), among others. In addition, the flexible adaptation pathways approach to manage climate change risks has been applied more widely by New York City and New York State (New York City Mayor's Office of Resiliency, 2019; Rosenzweig & Solecki, 2014) and utilities and infrastructure agencies across the United States, including San Diego Gas & Electric (Bruzgul et al., 2018; SDG&E, 2019) and Los Angeles Metro (Metro ECSD, 2019).

This flexible adaptation pathways approach allows Con Edison to develop an adaptation implementation plan in the near term, while adjusting adaptation strategies based on the actual climate conditions that emerge, thus reducing the cost of managing uncertainty. Under this adaptive approach, resilience measures can be sequenced over time to respond to changing conditions. For example, Con Edison may identify actions to implement now that protect against near-term climate changes and actions that are low and no regret, while leaving options open to protect against the wide range of plausible changes emerging later in the century. This implementation approach is preferred to implementing actions now that are optimized for present-day conditions or a single future outcome that ignores uncertainty.

[20] Long Range Plans are available at: https://www.coned.com/en/our-energy-future/our-energy-vision/long-range-plans

Illustrative Adaptation Pathway: Sea Level Rise Adaptation for Substation in FEMA + 3’ Floodplain

Flexible adaptation pathways could be developed for guiding the management and protection of specific assets or types of assets. Here, we consider a hypothetical electric substation that is potentially vulnerable to sea level rise, as it is located within the FEMA + 3’ floodplain (and, as such, is protected up to FEMA + 3’ flood heights based on Con Edison’s current design standards). This adaptation pathway is presented as *illustrative*; while it is grounded in the types of strategies that Con Edison would use for substation flood defense, a ready-to-implement pathway for implementation would require site-specific analysis and may differ from this configuration.

Figure 25 ■ Illustrative flexible adaptation pathway for a hypothetical Con Edison substation in a current FEMA + 3' floodplain

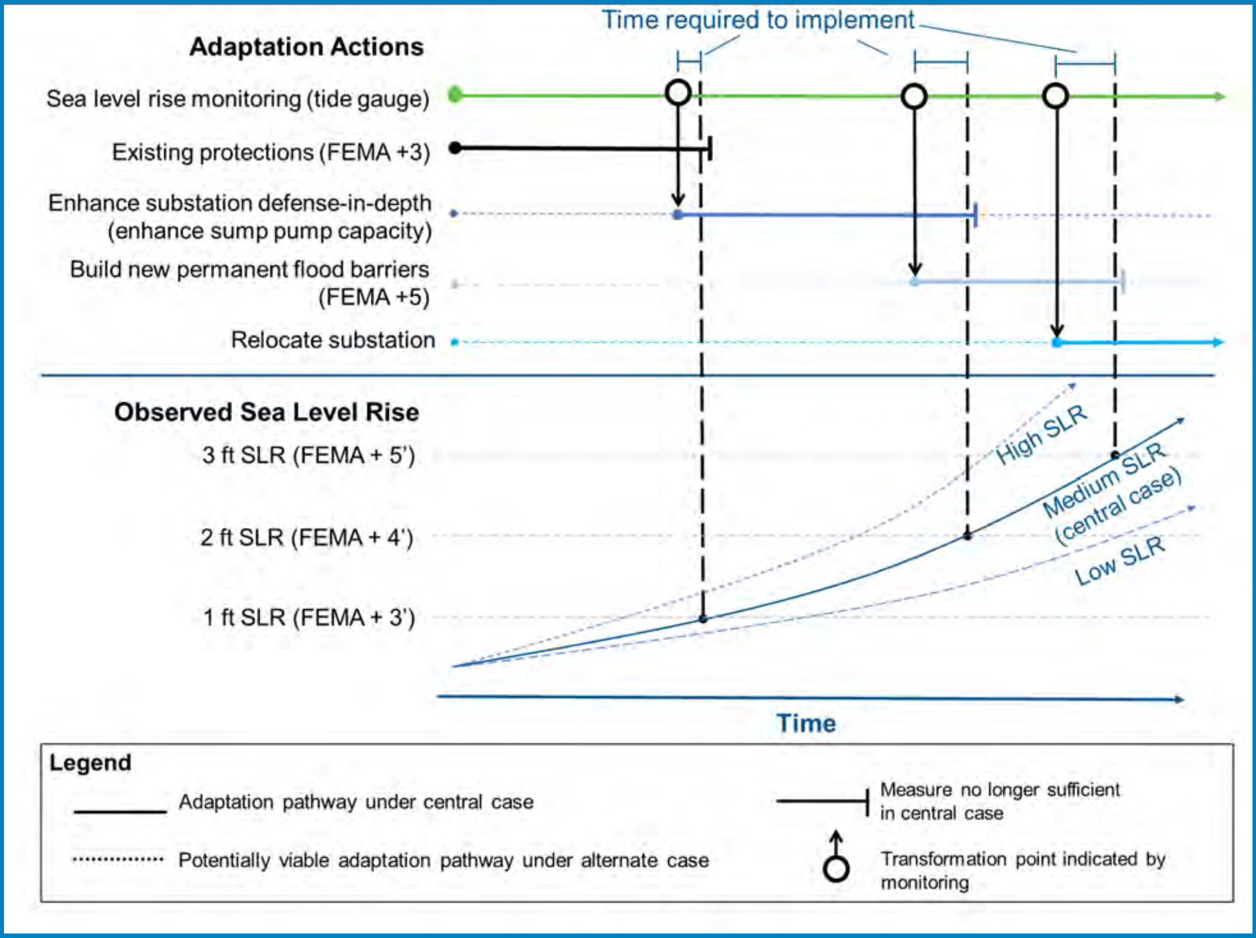


Figure 25 illustrates how the implementation of adaptation actions can be phased over time, with the implementation of new measures being triggered by observed sea level rise in excess of certain thresholds (transformation points). The timing of these transformation points is indicated by monitoring the rate of sea level rise at a local tide gauge (green line). Transformation points are set based on the point at which Con Edison needs to take action in order to implement a higher standard of protection before existing protections become insufficient.

In this adaptation pathway diagram, the implementation schedule of adaptation measures is illustrated based on a "central" sea level rise case. Measures based on this central scenario are illustrated with solid lines. If the actual pace of sea level rise deviates from the central case, monitoring of sea level rise may necessitate an accelerated or delayed implementation schedule

In this example, it is assumed that the substation already has existing protections to FEMA + 3′ based on Con Edison's post-Superstorm Sandy hardening measures (black line). However, these protections will no longer be sufficient to provide the requisite 2 feet of freeboard under a 100-year flood scenario once sea level rise surpasses 1 foot.

- A trigger slightly under 1 foot leads to the first adaptation option, which is to supplement the substation's defense-in-depth strategy with additional sump pump capacity.
- The second adaptation option is triggered when sea level rise approaches 2 feet, and includes building new permanent flood barriers to a FEMA + 5′ level.
- The final adaptation option, relocating the substation entirely, is triggered when sea level rise approaches 3 feet.

Each trigger is far enough in advance of the critical risk threshold (each foot of sea level rise, in this case) to have time for full implementation of the adaptation option.

Such a flexible adaptation pathway can allow Con Edison to better manage the costs of adaptation in the face of uncertainty, facilitating a prudent approach that avoids adapting too early or too late.

Signposts provide information that is critical for adaptive management decisions. Broad categories of signposts that Con Edison could consider monitoring include:

- **Climate variable observations and best available climate projections:** An awareness of recent and present climate conditions and their rates of change are key when determining potential asset exposure and risk. As described above, Con Edison currently operates a number of stations that monitor climate variables and is finalizing plans to expand the number of monitoring locations. Furthermore, access to the most recent and best available climate projections and expert knowledge is critical when updating plans for potential future scenarios as the science advances. In some cases, thresholds for action under climate variable and projection signposts may be determined by how quickly changes in climate conditions are approaching existing design or operational specifications.
- **Climate impacts:** Con Edison is already experiencing extreme weather and climate impacts to assets, operations and internal processes, and customers. Recognizing the risks, Con Edison is already conducting monitoring to identify areas of heightened vulnerability in its systems. Continued monitoring and evaluation of highest risk assets for impacts or near impacts can provide information about when and where additional adaptation options may be required.
- **Policy, societal, and economic conditions:** Evolving external conditions may affect climate-related decision making and areas of need throughout the service territory. Con Edison is already monitoring signposts for external conditions related to policies, society, and economies as part of its long-range plans. Additional external conditions may shift with a changing climate, such as adaptation strategies and investments led by the city.

The Study team identified a set of example signposts within each category, summarized in Table 9. Con Edison could consider coordinating with the city on NPCC's proposed New York City Climate Change Resilience Indicators and Monitoring System (Blake et al., 2019), where overlap and efficiencies in monitoring signposts may exist.

Table 9 ■ Example signposts for a flexible adaptation pathways approach

Category	Example Signposts
Climate variable observations and best available climate projections	• *Chronic variables:* Rate of change in TV, cooling degree-days, heating degree-days, sea levels, etc. relative to historical • *Extreme weather variables:* Number of days overheat index thresholds, storm surge levels, frequency of various storm types in the greater region, wind speeds, heat wave intensity and duration, intense precipitation levels, etc. • Updates to the best available climate projections: NPCC, IPCC, National Climate Assessment, etc.
Climate impacts	• *Assets:* Extent and magnitude of the costs of keystone asset damages (e.g., substations or power lines downed), damages incurred by events with different combinations of extreme weather, etc. • *Operations and internal processes:* Frequency of heat-related contingencies in the network and non-network systems, etc. • *Customers:* Number, spatial extent, and duration of outages caused by extreme weather, especially noting outages experienced by critical infrastructure and interdependent systems, etc.
Policy, societal, and economic conditions	• *Policy:* Updates to New York City design guidelines, etc. • *Societal:* Community-scale flood protection strategies led by New York City (e.g., East Side Coastal Resiliency Project), population shifts (e.g., retreat), etc. • *Economic:* Insurance prices and availability, etc.

Selecting Cost-Effective Solutions

As outlined in this Study, adapting to climate change will require investments in infrastructure and processes. Although some adaptation will be achieved through co-benefits from investments that Con Edison makes under existing processes, such as using distributed energy resources to meet growing electricity demand, other adaptation will require investments over and above those previously planned. The costs of those investments will ultimately be reflected in customers' bills. In order to minimize the financial impact of adapting to climate change, a cost-effective resilience planning process should identify a target level of resilience along with associated metrics, strike a balance between proactive and reactive spending, consider both the costs and benefits to customers, and select adaptation strategies that provide optimal benefit at the lowest cost.

As the energy industry grapples with how best to build resilience to the changing climate, the issue of how to quantify the resilience of energy systems is front and center. There is currently no standard *set of metrics* for the resilience of energy systems. A 2017 report from the National Academies of Sciences, Engineering, and Medicine found that "there are no generally agreed-upon resilience metrics [for the electricity sector] that are widely used today," also noting a contrast with the well-established set of electricity reliability metrics (NAS, 2017).

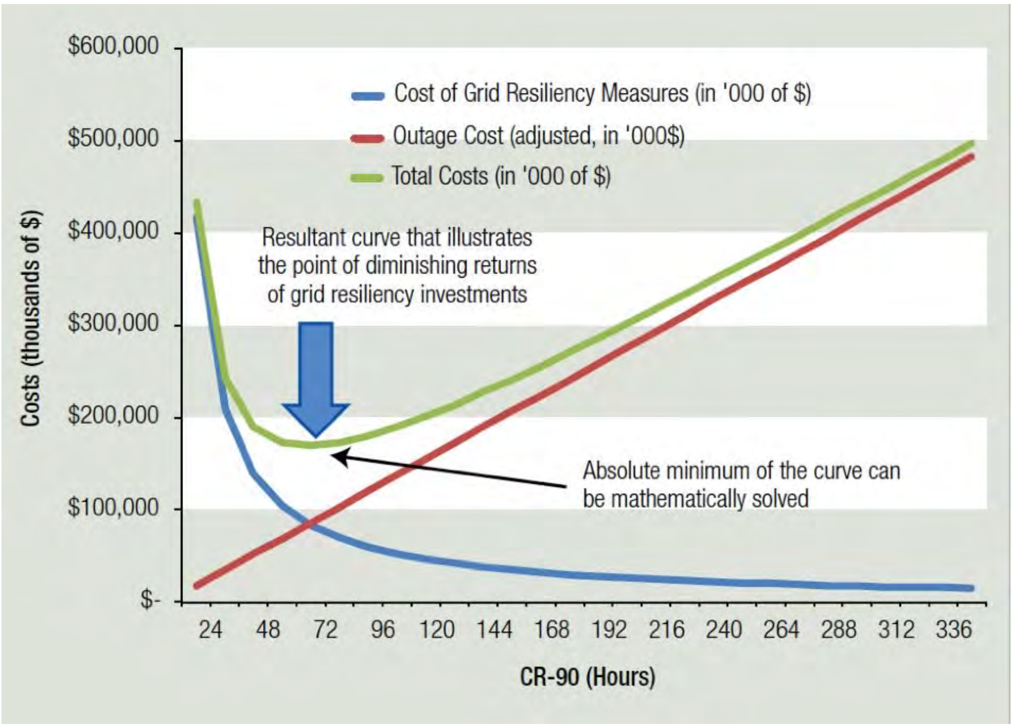
While there are a wide variety of energy resilience metrics that have been proposed or piloted in various contexts, most of these metrics fit within one of two broad categories. *Performance-based* metrics seek to quantify the resilience of the system through measurement of infrastructure performance during actual or modeled disruptive events. *Attribute-based* metrics, on the other hand, measure the presence of characteristics or features that are known or predicted to increase resilience performance in the event of a disruption. (Vugrin, Castillo, & Silva-Monroy, 2017).

Con Edison's storm hardening investments after Superstorm Sandy were guided by a combination of performance-based metrics, such as "past performance" in the selective undergrounding of feeders, and attribute-based metrics, such as "reducing the number of customers served by a single circuit to fewer than 500 customers," and adding "isolation devices to spurs and sub-spurs with open wire that are more than 2 spans in length" (Con Edison, 2013). Since the development of metrics is an active area of research and discussion, Con Edison could keep abreast of industry advances in resilience metrics for energy systems and incorporate those advances, where applicable, into its planning framework.

Even after a resilience metric(s) is selected, the question of exactly *how much* to spend on resilience or what the *right* level of resilience is, remains. One approach is to compare the societal cost of an outage against the cost of resiliency measures to shorten that outage. The total cost curve developed by ICF's Mihlmester and Kumaraswamy (Figure 26) is one example of such an approach (Mihlmester & Kumaraswamy, 2013). It shows for a hypothetical utility the post-outage time needed to restore service to 90% of customers, known in the industry as "CR-90." In this case, the lowest total costs, combining customer outage and grid-hardening costs, would be about $169 million for a 65-hour CR-90 restoration time. The graph also shows that getting the CR-90 time to less than a day would cost more than twice that amount.

For Con Edison, the "right" level of resiliency investment will be strongly linked to the climate projection design pathway selected for each of the climate stressors identified for resiliency planning.

Figure 26 ■ Total cost of resiliency (Mihlmester & Kumaraswamy, 2013)



Utilities have historically *reacted* to events, primarily because they lacked relevant climate projections and clear guidance or best practices for a methodology necessary to inform *proactive* adaptation and resiliency investments in infrastructure (California Energy Commission, 2018). Similarly, prior to conducting this study, Con Edison had limited information to guide proactive investments. The U.S. Department of Energy's North American Energy Resilience Model (U.S. DOE, 2019) highlights the need to "transition from the current reactive state-of-practice to a new energy planning and operations paradigm in which we proactively anticipate damage to energy system equipment, predict associated outages and lack of service, and recommend optimal mitigation strategies."

The Study team has described an overarching resilience management framework in Figure 12, designed to minimize the impacts of extreme events throughout asset life cycles. The framework considers how the system can withstand, absorb, recover, and adapt to risks posed by extreme events. To succeed, each measure of a resilient system requires *proactive planning and investments*.

Consideration of the *costs and benefits to customers* is a key component in the selection of adaptation options. Con Edison's capital budget cycle currently considers costs and benefits through an investment optimization and management process that compares the wide array of capital investments the company makes across its various business units. The process calculates a "strategic value" for each project to compare the benefit of investing in one capital project or program over another and to ensure that spend is in alignment with the company's corporate strategy. The strategic value is conveyed by a set of strategic drivers, each with relative weights, based on the company's long-term objectives. The strategic value of each capital project is assessed against that of other projects, and an optimized portfolio of capital projects is generated. While the strategic drivers include *reliability* and customer satisfaction components, the drivers do not include or consider the *resiliency* benefit of a project.

Con Edison developed and used a cost-benefit calculation model to prioritize storm hardening investments after Superstorm Sandy. The model estimated "the vulnerability of individual electric system assets based on the impact of electric system damage to customers and supporting critical infrastructure, the duration of an electric service outage, the likelihood of those assets being affected by either flooding or wind damage, and the reduction in vulnerability of those assets because of storm hardening initiatives." (Con Edison, 2014)

Con Edison's current distribution system planning process includes an evaluation of customer benefits resulting from investments. Con Edison's Distributed System Implementation Plan (DSIP) (Con Edison, 2016) includes the consideration of distributed energy resources as one option to meeting growing demand. As part of Con Edison's DSIP, the company has developed a Benefit Cost Analysis (BCA) Handbook that describes how to calculate individual benefits and costs. The BCA includes consideration of the unit cost of a particular option, per megawatt of delivery capacity, as well as an option's "social cost." Social cost accounts for the monetization of air pollution and carbon dioxide, using 20-year forecasts of marginal energy prices, the cost of complying with regulatory programs for constraining these pollutants, and the price paid for renewable energy credits. The social cost metric also qualitatively accounts for avoided water and land impacts. Beyond these environmental aspects, social cost accounts for net avoided restoration and outage costs to Con Edison, as well as net non-energy benefits (such as avoided service terminations, avoided uncollectable bills, and avoided noise and odor impacts).

This Study illustrates the use of multi-criteria analysis to compare criteria that may be difficult to quantify or monetize, or that may not be effectively highlighted in the financial analysis. This process identified additional complementary metrics that could be included in Con Edison's planning and budget prioritization process to account for uncertainty in climate outcomes. These metrics fall into two categories: co-benefits and adaptation benefits. Under a non-stationary climate, co-benefits (environmental, reputational, safety, and customer financial benefits) can help planners more comprehensively evaluate response options considering the additional challenges that climate change can pose on the system. In addition, consideration of adaptation benefits (flexibility, reversibility, robustness, proven technology, and customer's resilience) support long-term planning under climate uncertainty. These metrics allow for effective implementation of adaptation measures over time to achieve resilience. Con Edison's current processes include some of the metrics identified in the multi-criteria analysis (environmental and safety) but not others (customer's resilience and reversibility). Con Edison could work to incorporate this wider set of metrics as it incorporates resiliency planning into its broader capital budgeting process.

Key Issues to Be Addressed for Effective Implementation

Changes in the Policy/Regulatory and Operating Environment

Changes in the policy/regulatory and operating environment other than climate change were not accounted for in this Study but will be an important consideration when moving toward implementation. For example, the prioritization of adaptation strategies, and even the understanding of vulnerabilities, will need to consider these other drivers of change. Likewise, as Con Edison undertakes studies on how these factors will impact its business, climate change impacts could be factored into those studies. Some examples of possible changes in Con Edison's operating environment include:

- **Climate change and clean energy targets:** New York State and New York City have both adopted ambitious greenhouse gas emissions reduction targets (State of New York, 2019; City of New York, 2014), which will drive changes in the adoption of renewables, transportation electrification, energy storage, and so forth. It will also impact relative demand across the commodities (e.g., decreasing gas demand and increasing electricity demand).

- **Technological advances:** Advances in solar photovoltaics, energy storage, electric vehicles, and electrification of space heating are changing how and where electricity is generated and used.
- **Customer response to climate change impacts:** Customers will also have to respond to climate change impacts. This may include shifting away from flooded coastlines (depending on city-scale investments in coastal protection) and, with it, shifting demand away from portions of Con Edison's system.

Coordination with External Entities

Another critical need for effective implementation is coordination with external entities, including the City of New York and Westchester County, industry groups, equipment manufacturers, and others. Con Edison has limited authority to address certain vulnerabilities, such as the capacity of the city's stormwater system, so coordination is necessary for developing a more resilient system. In addition, coordination is needed to ensure that Con Edison is not over-investing in locations that the city plans to protect or retreat from. This project seeded the necessary relationships; however, the continuation of the interactions will need to be specified in the governance section of the upcoming implementation plan.

Establishing a Reporting and Governance Structure

Con Edison will need a continuing approach to updating stakeholders on climate risk management progress. Of the various reporting options, many companies are opting to follow the relatively new framework outlined by the Task Force on Climate-Related Financial Disclosures (TCFD).[21] This framework emphasizes the need to assess both the physical risks of climate change, which is covered in this study, as well as the risks and opportunities presented by transition to a low-carbon economy. It requires consideration of the financial implications of the risks and opportunities, as well as a measurable risk management plan that is integrated with a strong governance structure.

Two risks that were not explored in this study, but would fit well in the TCFD framework, include:

- **Costs and penalizations from service failure and outages:** Costs associated with an outage event include restoration; collateral damage; customer claims; penalties, fines, audits, remediation, and reporting; and the financial impact of lost confidence. For example, in 2007, Con Edison was penalized $18 million for its 2006 service disruptions, which included a 9-day blackout in western Queens.
- **Credit rating:** Increasingly frequent and intense extreme weather events could also impact credit rating risks and insurance liabilities. Credit rating agencies like Standard & Poor's and Moody's have added "resiliency" as a component of their rating criteria, indicating the relevance of climate risk for creditworthiness (Shafroth, 2016). Similarly, utilities may be increasingly choosing to retain a higher level of insurance to cope with more frequent and destructive weather-related events. However, a higher level of insurance protection leads to higher costs that may ultimately be reflected on customers' bills. Thus, while not as visible as physical asset or planning vulnerabilities, climate risks related to credit and insurance can have an impact on the utility.

Establishing a governance structure will be crucial for the successful continuation of Con Edison's climate change adaptation work. The governance structure can be used to encourage and track progress on the implementation of adaptation strategies (i.e., performance against set metrics and targets), ensure specific

[21] For more information on the Task Force on Climate-Related Financial Disclosures, see https://www.fsb-tcfd.org/

people are on point for monitoring and implementing various strategies, and establish a frequency and process for reporting on risks and adaptation actions from individual employees to senior managers to Con Edison's board of directors.

Next Steps

As a next step from this Study, Con Edison will develop a detailed Climate Change Implementation Plan to operationalize the suggestions from this Climate Change Vulnerability Study. The implementation plan will:

- Review the Study and investigate whether recent progress in climate science may warrant inclusion.
- Select climate change pathway(s) to incorporate into design standards and procedures.
- Establish life cycle tables that provide timeframes of reference climate variables through 2080.
- Aggregate input from subject matter experts on changes required for specifications/procedures and choices for risk mitigation measures.
- Develop a timeline and written plan for the implementation of risk mitigation measures.
- Identify the scope and cost within the 5-year capital plan and 10- and 20-year long-range plans.
- Establish signposts for the re-evaluation of measure installation schedules.
- Conduct periodic progress meetings for external stakeholders.
- Recommend a governance structure for climate change monitoring and updating.

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APPENDICES

Appendices

To inform the conclusions of this Study, the Study team undertook a series of in-depth vulnerability assessments corresponding to the climate hazards representing outsized risks to Con Edison: temperature, humidity, precipitation, sea level rise, and extreme events. These are included as appendices. Each appendix includes detailed historical and projected climate conditions; corresponding climate-driven vulnerabilities to operations, planning, and infrastructure across the company's electric, gas, and steam systems; and potential adaptation strategies to mitigate vulnerabilities.

For each hazard, the Study team collaborated with Con Edison subject matter experts to conduct a rapid screen of the sensitivity of operations, planning, and infrastructure to support a risk-first approach. Vulnerabilities were then selected for more detailed analyses, which focused on understanding asset vulnerabilities to climate change and, in turn, relevant adaptation options and evaluation of their costs and co-benefits. These analyses informed the development of flexible solutions and signposts to guide implementation of potential adaptation options through time.

Ultimately, the five appendices provide key context for the climate science, vulnerabilities, and adaptation strategies discussed in this report, and as such, can be referenced for more comprehensive information in each subject area.

- **Appendix 1 – Temperature:** Identifies how projected gradual trends in increasing temperature may affect operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business.
- **Appendix 2 – Humidity, Temperature Variable, and Load:** Addresses climate variables—humidity (expressed through wet bulb temperature), heat waves, cooling degree-days, heating degree-days, and the combination of projected changes in wet and dry bulb temperatures—that have a direct effect on system loads and reliability. These variables are also specifically addressed in specifications and procedures associated with upgrading system capacity and maintaining system reliability.
- **Appendix 3 – Changes in Precipitation Patterns:** Discusses the potential for climate-driven changes in rainfall and frozen precipitation in Con Edison's service territory, and the potential impacts of those changes on Con Edison's assets and operations.
- **Appendix 4 – Sea Level Rise and Changes in Coastal Storm Surge Potential:** Examines the ways in which changes in sea level may affect operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business.
- **Appendix 5 – Extreme Events:** Describes how extreme weather events (hurricanes, nor'easters, and heat waves), as well as concurrent or consecutive extreme events, may become more frequent and severe due to climate change, and considers their potential impact on operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business over the coming century.

Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-2, Sub 1219

April 13, 2020

Exhibit JMV-TF-5

Exhibit JMV-TF-5: Literature Review of Climate-Related Risks

#	Category	Date Published	Source	Author (if relevant)	Title / Link
1	Financial Institution Actions on Climate Risk	January, 2020	Wall Street Journal	Ronald P. O'Hanley, CEO, State Street,	Sustainability Is Part of Good Risk Assessment
2	News & Finanical Reporting Coverage; NC Context	January, 2020	Asheville Citizen-Times	Joel Burgess	Asheville declares 'climate emergency,' looks to end greenhouse gas emissions 2030
3	News & Finanical Reporting Coverage	January, 2020	WFAE	David Boraks	State and Local Leaders Set Climate Goals, But Can We Meet Them?
4	Context in North Carolina	January, 2020	NC Climate Change Interagency Council	Kenneth Kunkel, David Easterling	Presentation of January 22 Meeting
5	News & Financial Reporting Coverage	January, 2020	UtilityDive	Catherine Morehouse	Ameren, Xcel, Dominion, Duke among most at-risk from changing climate: Moody's
6	News & Financial Reporting Coverage	January, 2020	Energy News Network	Allen Best	Tri-State CEO says wholesaler's clean energy transition will pay dividends
7	News & Finanical Reporting Coverage	January, 2020	Charlotte Business Journal	John Downey	Duke Energy ranks high among utilities at risk from hurricanes, other impacts of climate change
8	News & Financial Reporting Coverage	January, 2020	Wall Street Journal	Greg Ip	For the Economy, Climate Risks are No Longer Theoretical
9	Financial Institution Actions on Climate Risk	January, 2020	BlackRock	Larry Fink, CEO, BlackRock	Annual Letter to CEOs
10	Financial Institution Actions on Climate Risk	January, 2020	BlackRock	Larry Fink, CEO, BlackRock	Annual Letter to Clients

11	News & Financial Reporting Coverage	January, 2020	NYTimes	Andrew Ross Sorkin	Blackrock CEO Larry Fink: Climate Crisis Will Reshape Finance
12	News & Financial Reporting Coverage	January, 2020	Energy and Policy Institute	Joe Smyth	Financial analysts expect decarbonization will benefit utility ratepayers adn shareholders
13	Duke Publications and Statements	January, 2020	Duke Energy Florida	n/a	Amicus Curiae Comments in FPL SolarTogether Petition Proceeding
14	News & Financial Reporting Coverage	January, 2020	POWER	William Friedman	Structural Effects of Climate Change on the Utility Business
15	Technical Analysis	January, 2020	NREL	Reiko Matsuda-Dunn, Michael Emmanuel, Erol Chartan, Bri-Mathias Hodge, Gregory Brinkman	Carbon-Free Resource Integration Study
16	Technical Climate Risk Analysis	January, 2020	McKinsey Global Institute	n/a	Climate risk and response: Physical Hazards and socioeconomic impacts
17	News & Financial Reporting Coverage	January, 2020	Financial Times	Robin Wigglesworth	State Street vows to turn up the heat on ESG standards
18	News & Financial Reporting Coverage	December, 2019	The Atlantic	Robinson Meyer	Investment Bankers are Now Waging the War on Coal
19	Context in North Carolina	December, 2019	North Carolina Clean Energy Technology Center	n/a	Planning an Affordable, Resilient, and Sustainable Grid in North Carolina
20	Financial Institution Scrutiny on Climate Risk	December, 2019	n/a	Robert Litterman, Chair of Climate-Related Risk Subcommittee	Letter to Commodity Futures Trading Commission
21	News & Financial Reporting Coverage	December, 2019	Duke Energy Illumination	Jessica Wells	Lineman's idea leads to microgrid in Great Smoky Mountains National Park
22	Technical Climate Risk Analysis	December, 2019	UN Principles for Responsible Investment	n/a	Impacts of the Inevitable Policy Response on Equity Markets
23	News & Finanical Reporting Coverage	December, 2019	S&P Global	Guarang Dholakia	Duke Energy tops operating US coal, gas capacity ownership
24	News & Financial Reporting Coverage	December, 2019	S&P Global	Jeffrey Ryser	US utilities race to slash emissions as ESG reporting takes off

25	News & Financial Reporting Coverage	December, 2019	S&P Global	Stephanie Tsao, Richard Martin	Overpowered: What a US gas-building spree continues despite electricity glut
26	News & Financial Reporting Coverage	December, 2019	The Guardian	Julia Kollewe	Coal power becoming 'uninsurable' as firms refuse cover
27	News & Financial Reporting Coverage	December, 2019	LA Times	Sammy Roth	Do PG&E and Edison need higher profits? California is about to decide
28	Technical Climate Risk Analysis	December, 2019	UC Berkeley Law: Center for Law, Energy & Environment	n/a	California Climate Risk: Insurance-based Approaches to Mitigation and Resilience
29	Financial Institution Scrutiny on Climate Risk	December, 2019	International Monetary Fund	Pierpaolo Gripaa, Jochen Schmittmann, and Felix Suntheim	Climate Change and Financial Risk
30	Risk Management Guidance	December, 2019	MJ Bradley & Associates	n/a	Key Considerations for Electric Sector Climate Resilence Policy and Investments
31	Publications from Peer Utilities	December, 2019	Consolidated Edison	n/a	Climate Change Vulnerability Study
32	Risk Management Guidance	November, 2019	UN Principles for Responsible Investment	n/a	Fiduciary Duty in the 21st Century
33	News & Financial Reporting Coverage	November, 2019	Economist	n/a	Firms that analyse climate risks are the latest hot property
34	News & Financial Reporting Coverage	November, 2019	WGBH	Deanna Moran	Utilities--Like Eversource and National Grid--Are Weak Links in Climate Defense
35	Miscellaneous	November, 2019	US Senator Brian Schatz	n/a	Schatz Introduces New Legislation to Ensure U.S. Financial System is Prepared for Climate Change
36	Academic Research on Climate Risk	November, 2019	Swiss Finance Institute	Philipp Krueger, Zacharias Sautner, Laura T. Starks	The Importance of Climate Risks for Institutional Investors
37	News & Financial Reporting Coverage	November, 2019	The Denver Post	Judith Kohler	Tri-State's conflicts with members a factor in the downgrade of its credit rating

38	News & Financial Reporting Coverage	November, 2019	Bloomberg	Kevin Crowley	Exxon's Credit Rating Oulook Lowered by Moody's on Cash Burn
39	Financial Institution Actions on Climate Risk	November, 2019	European Investment Bank	n/a	EU Bank launches ambitious new climate strategy and Energy Lending Policy
40	News & Financial Reporting Coverage	November, 2019	Risk.net	Tom Osborn	Climate Change Spells Death of Certainty
41	News & Fiancial Reporting Coverage	November, 2019	New York Times	Jeanna Smialek	Why the Fed, Long Reticent, Has Started to Talk About Climate Change
42	News & Financial Reporting Coverage	November, 2019	Bloomberg Businessweek	Danielle Moran	Muni Bonds Contain New Fine Print: Beware of Climate Change
43	News & Financial Reporting Coverage	October, 2019	Foreign Times	Masood Ahmed	Disclosure of climate risk will improve decision-making
44	Duke Publications and Statements	October, 2019	Charlotte Observer	Stephen DeMay	Duke Energy NC president: Climate and the case for natural gas
45	Duke Publications and Statements	October, 2019	Utility Dive	Catherine Morehouse	Duke VP likens gas plant buildout strategy to 15-year home mortgage on path to zero carbon
46	Risk Management Guidance	October, 2019	Western Resource Advocates	Aaron Kressig	Damage Control: How Electric Utilities are Planning for Wildfires & the Costs of Climate Change
47	News & Finanical Reporting Coverage	October, 2019	New York Times	Christopher Flavelle	Bank Regulators Present a Dire Warning of Financial Risks from Climate Change
48	Financial Institution Scrutiny on Climate Risk	October, 2019	n/a	Frank Elderson, Chair, Network for Greening the Financial System	Introductory Statement to US Senate Democrats' Special Committee on the Climate Crisis
49	News & Finanical Reporting Coverage	October, 2019	The Royal Gazette	Scott Neil	Axis backs away from coalmine project
50	News & Financial Reporting Coverage	October, 2019	InsideClimateNews	Dan Gearino	Utilities are Promising Net Zero Carbon Emissions, But Don't Expect Big Changes Soon

51	Context in North Carolina	October, 2019	Noth Carolina Department of Environmental Quality	n/a	North Carolina Clean Energy Plan
52	Financial Institution Scrutiny on Climate Risk	October, 2019	Federal Reserve Bank of San Francisco	n/a	Strategies to Address Climate Change Risk in Low-and Moderate-income Communities
53	Risk Management Guidance	September, 2019	Task Force on Climate-Related Financial Disclosures	n/a	Good Practice Handbook
54	News & Finanical Reporting Coverage	September, 2019	Citizen Truth	Elana Sulakshana	First Major US Insurance Company to Stop Insuring and Investing in Coal
55	Financial Institution Scrutiny on Climate Risk	September, 2019	Majority Action	n/a	Climate in the Boardroom: How Asset Manager Voting Shaped Corporate Climate Action in 2019
56	Regulatory Action on Climate Risk	September, 2019	California Public Utiltiies Commission	Commissioner Liane M. Randolph	Proposed Decision on Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation
57	Technical Climate Risk Analysis	September, 2019	Council on Foreign Relations	Amy Myers Jaffe, Joshua Busby, Jim Blackburn, Christina Copeland, Sara Law, Joan Ogden, Paul Griffin	Impact of Climate Risk on the Energy System
58	Technical Climate Risk Analysis	September, 2019	London School of Economics Grantham Research Institute on Climate Change and the Environment	Ruth DeFries et al	The missing economic risks in assessments of climate change impacts
59	Duke Publications and Statements	September, 2019	Duke Energy	n/a	Duke Energy aims to achieve net-zero carbon emissions by 2050
60	Duke Publications and Statements	August, 2019	Duke Energy	n/a	NCUC ISOP Technical Conference Presentation
61	News & Financial Reporting Coverage	August, 2019	Toronto Star	Dianne Saxe	Climate crisis puts corporate boards on the hot seat
62	News & Finanical Reporting Coverage	August, 2019	Raleigh News & Observer	Richard Stradling	NCDOT to lay off hundreds of workers as storms, lawsuits sap its budget

63	News & Financial Reporting Coverage	August, 2019	Bloomberg	Kelly Gilblom	Big Money Starts to Dump Stocks that Pose Climate Risks
64	News & Financial Reporting Coverage	August, 2019	Utility Dive	Herman K. Trabish	As co-ops struggle with stranded fossil fuel assets, Tri-State may finally embrace the energy transition
65	News & Financial Reporting Coverage	August, 2019	Governing	Liz Farmer	Will Climate Change Lead to a 'Fiscal Tsunami'?
66	News & Finanical Reporting Coverage	August, 2019	InsideClimateNews	Kristoffer Tigue	Climate Change Becomes an Issue for Ratings Agencies
67	News & Financial Reporting Coverage	August, 2019	BusinessGreen	Toby Hill	Climate risk posed by oil, gas, and coal leaves energy investors on shaky ground
68	Risk Management Guidance	August, 2019	Columbia Center on Global Energy Policy	John J MacWilliams, Sarah La Monaca, and James Kobus	PG&E: Market and Policy Perspectives on the First Climate Change Bankruptcy
69	News & Financial Reporting Coverage	July, 2019	Foreign Policy	Adam Tooze	Why Central Banks Need to Step Up on Global Warming
70	News & Financial Reporting Coverage	July, 2019	InsideClimateNews	John Lippert	Could Climate Change Spark a Financial Crisis? Candidates Warn Fed It's a Risk
71	News & Financial Reporting Coverage	July, 2019	Forbes	Jeff McMahon	In Conservative Indiana, Utility Chooses Renewables over Gas as it Retires Coal Early
72	Financial Institution Scrutiny on Climate Risk	June, 2019	Commodity Futures Trading Commission (CFTC)	n/a	CFTC Public Meeting Addressing Climate-Related Risks
73	Financial Institution Scrutiny on Climate Risk	June, 2019	Aspen RE	n/a	Climate Change and the (Re)insurance Implications
74	News & Financial Reporting Coverage	June, 2019	S&P Global	Michael Copley	US regulators examining the financial risk of climate change
75	News & Financial Reporting Coverage	June, 2019	WIRED	Sara Harrison	Companies Expect Climate Change to Cost Them $1 Trillion in 5 Years

76	NGO Review of Duke Climate Governance	June, 2019	CERES	n/a	Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the Untied States
77	Financial Institution Scrutiny on Climate Risk	June, 2019	State Street Global Advisors	Rakhi Kumar, Michael Younis	Climate-Related Disclosures in Oil and Gas, Mining, and Utilities: The Current State and Opportunities for Improvement
78	Risk Management Guidance	June, 2019	Deloitte Center for Financial Services	n/a	Climate Risk: Regulators Sharpen their Focus
79	Risk Management Guidance	May, 2019	Task Force on Climate-Related Financial Disclosures	n/a	2019 Status Report
80	News & Financial Reporting Coverage	May, 2019	GreenBiz	Joel Makower	Wall Street, ESG, and the Wild West
81	News & Finanical Reporting Coverage	May, 2019	WLOS	Rob Bradley	Drought & deluge: Extreme weather events increasing across WNC
82	Publications from Peer Utilities	May, 2019	Ameren	n/a	Building a Cleaner Energy Future
83	Financial Institution Scrutiny on Climate Risk	April, 2019	n/a	Sarah Breeden, Executive Director, International Bank Supervisoin	Avoiding the storm: Climate Change and the financial system
84	Financial Institution Scrutiny on Climate Risk	April, 2019	n/a	Hans Hoogervorst, Chair of International Accounting Standards Board (IASB)	Speech to Climate-Related Financial Reporting Conference
85	Technical Climate Risk Analysis	April, 2019	BlackRock	Andre Bertolotti, Debarshi Basu, Kenza Akallal, Brian Deese	Climate Risk in the US Electric Utility Sector: A Case Study
86	Technical Climate Risk Analysis	April, 2019	McKinsey & Company	n/a	Why, and How, utilities should start to manage climate-change risk
87	Financial Institution Scrutiny on Climate Risk	April, 2019	Network for Greening the Financial System	n/a	A call for action: Climate change as a source of financial risk

88	Financial Institution Scrutiny on Climate Risk	April, 2019	Australian Accounting Standards Board	n/a	Climate-related and other emerging risks disclosures: assessing financial statement materiality using AASB/IASB Practice Statement 2
89	Technical Climate Risk Analysis	April, 2019	BlackRock Investment Institute	Brian Deese, Philipp Hildebrand, Rich Kushel, Isabelle Mateos y Lago	Getting Physical: Scenario analysis for assessing climate-related risks
90	Technical Climate Risk Analysis	April, 2019	NARUC	n/a	The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices.
91	Duke Publications and Statements	March, 2019	Duke Energy	n/a	Annual Shareholder Meeting Proxy Statement
92	Risk Management Guidance	March, 2019	Centre for Policy Development	Noel Hutley	Climate Change and Directors' Duties
93	Publications from Peer Utilities	March, 2019	Xcel	n/a	Building a Carbon-Free Future
94	Technical Climate Risk Analysis	March, 2019	Vibrant Clean Energy, Energy Innovation	Eric Gimon, Mike O'Boyle, Christopher Clack, Sarah McKee	The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources
95	Duke Publications and Statements	February, 2019	Duke Energy	n/a	Form 10-K
96	Financial Institution Scrutiny on Climate Risk	February, 2019	Climate Majority Project	n/a	Institutional Investor Statement Regarding Decarbonization of Electric Utilities
97	News & Financial Reporting Coverage	February, 2019	Reuters	Ross Kerber	Big U.S. pension funds ask electric utilities for decarbonization plans
98	Financial Institution Scrutiny on Climate Risk	February, 2019	Climate Majority Project	n/a	Net-Zero by 2050: Investor risks and opportunities in the context of deep decarbonization of electric generation
99	News & Finanical Reporting Coverage	January, 2019	Wall Street Journal	Russell Gold	PG&E: The First Climate-Change Bankruptcy, Probably Not the Last
100	News & Financial Reporting Coverage	January, 2019	Reuters	Sharon Bernstein, Suzanne Barlyn	Insurance losses for California wildfires top $11.4 billion

101	Financial Institution Scrutiny on Climate Risk	November, 2018	Moody's Investors Service	n/a	Moody's approach to climate risk
102	Context in North Carolina	October, 2018	n/a	Governor Roy Cooper	Executive Order No. 80
103	Technical Climate Risk Analysis	May, 2018	National Climate Assessment	Craig Zamuda, Daniel Bilello, Gunter Conzelmann, Ellen Mecray, Ann Satasngi, Vincent Tidwell, Brian Walker	Energy Supply, Delivery, and Demand
104	Duke Publications and Statements	March, 2018	Duke Energy	n/a	2017 Climate Report to Shareholders
105	Risk Management Guidance	February, 2018	US Government Accountability Office	n/a	Climate-related Risks: SEC Has Tkaen Steps to Clarify Disclosure Requirements
106	Financial Institution Scrutiny on Climate Risk	November, 2017	Moody's Investors Service	n/a	Evaluating the Impact of Climate Change on US state and local issuers
107	Risk Management Guidance	August, 2017	The Brattle Group	n/a	Compensating Risk in Evolving Utility Business Models
108	Risk Management Guidance	June, 2017	Task Force on Climate-Related Financial Disclosures	n/a	Recommendations of the Task Force
109	Risk Management Guidance	June, 2017	Task Force on Climate-Related Financial Disclosures	n/a	The Use of Scenario Analysis in Disclosure of Cliamte-Related Risks and Opportunities
110	Risk Management Guidance	May, 2017	50/50 Climate Project	n/a	Utility Climate Change Readiness: A Business Plan Analysis
111	Technical Climate Risk Analysis	January, 2017	The Rhodium Group	Kate Laresen, John Larsen, Whitney Herndon, Michael Delgado, Shashank Mohan	Assessing the Effect of Rising Temperatures; The Cost of Climate Change to the US Power Sector
112	Risk Management Guidance	January, 2017	Center for International Environmental Law	n/a	Trillion Dollar Transformation: Fiduciary Duty, Divestment, and Fossil Fuels in an Era of Climate Risk

113	Risk Management Guidance	September, 2016	US Department of Energy	n/a	Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning
114	Risk Management Guidance	September, 2016	Columbia Sabin Center for Climate Change Law	Payal Nanavati and Justin Gundlach	Legal Tools for Climate Adaptation Advocacy: The Electric Grid and Its Regulators -- FERC and State Public Utility Commissions
115	Financial Institution Scrutiny on Climate Risk	September, 2016	BlackRock	n/a	Adapting Portfolios to Climate Change
116	Academic Research on Climate Risk	May, 2016	Journal of Business Ethics	Juhyun Jung, Kathleen Herbohn, Peter Clarkson	Carbon Risk, Carbon Risk Awareness, and the Cost of Debt Financing
117	Risk Management Guidance	January, 2016	California Public Utilities Commission	Kristin Ralff-Douglas	Climate Adaptation in the Electric Sector: Vulnerability Assessments & Resilience Plans
118	Publications from Peer Utilities	January, 2016	PG&E	n/a	Climate Change Vulnerability Assessment
119	Financial Institution Scrutiny on Climate Risk	September, 2015	Mark Carney, Governor of the Bank of England, Chairman of the Financial Stability Board	n/a	Breaking the Tragedy of the Horizon--Climate Change and Financial Stability
120	Academic Research on Climate Risk	September, 2015	Energy Economics	John E. Bistline	Electric sector capacity planning under uncertainty: Climate policy and natural gas in the US
121	Academic Research on Climate Risk	June, 2014	n/a	Piere Audinet, Jean-Christophe Amado, Ben Rabb (World Bank)	Climate Risk Management Approaches in the Electricity Sector: Lessons from Early Adapters
122	Academic Research on Climate Risk	June, 2014	Lawrence Berkeley National Lab	Peter Larsen, et al. (Lawrence Berkeley National Laboratory)	Exploring the Reliability of U.S. Electric Utilities
123	Risk Management Guidance	March, 2014	Edison Electric Institute	n/a	Before and After the Storm: A compilation of recent studies, programs, and policies related to storm hardening and resiliency
124	Risk Management Guidance	January, 2014	US Government Accountability Office	n/a	Climate Change: Energy Infrastructure Risks and Adaptation Efforts

125	Risk Management Guidance	September, 2011	BSR	n/a	Adapting to Climate Change: A Guide for the Energy and Utility Industry
126	Publications from Peer Utilities	January, 2010	Entergy	n/a	Building a Resilient Energy Gulf Coast
127	Duke Publications and Statements	2020	CDP	n/a	Duke Energy Response to Climate Change Questionnaire, 2019
128	Duke Publications and Statements	2019	CDP	n/a	Duke Energy Response to Climate Change Questionnaire, 2018
129	Publications from Peer Utilities	2019	SCE	n/a	Form 10-K
130	Publications from Peer Utilities	2019	Xcel	n/a	Form 10-K
131	Duke Publications and Statements	2018	CDP	n/a	Duke Energy Response to Climate Change Questionnaire, 2017

Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-2, Sub 1219

April 13, 2020

Exhibit JMV-TF-6

I/A

State of North Carolina

ROY COOPER

GOVERNOR

October 29, 2018

EXECUTIVE ORDER NO. 80

NORTH CAROLINA'S COMMITMENT TO ADDRESS CLIMATE CHANGE AND TRANSITION TO A CLEAN ENERGY ECONOMY

WHEREAS, North Carolina residents deserve to be better educated, healthier, and more financially secure so that they may live purposeful and abundant lives; and

WHEREAS, N.C. Const. art. XIV, § 5 requires the conservation, protection, and preservation of state lands and waters in public trust; and

WHEREAS, North Carolina is well positioned to take advantage of its technology and research and development sectors, along with its skilled workforce, to promote clean energy technology solutions and a modernized electric grid; and

WHEREAS, public-private partnerships in North Carolina foster market innovations and develop clean energy technology solutions that grow the state's economy; and

WHEREAS, the effects of more frequent and intense hurricanes, flooding, extreme temperatures, droughts, saltwater intrusion, and beach erosion have already impacted and will continue to impact North Carolina's economy; and

WHEREAS, climate-related environmental disruptions pose significant health risks to North Carolinians, including waterborne disease outbreaks, compromised drinking water, increases in disease-spreading organisms, and exposure to air pollution, among other issues; and

WHEREAS, to maintain economic growth and development and to provide responsible environmental stewardship, we must build resilient communities and develop strategies to mitigate and prepare for climate-related impacts in North Carolina.

NOW, THEREFORE, by the authority vested in me as Governor by the Constitution and the laws of the State of North Carolina, **IT IS ORDERED**:

1. The State of North Carolina will support the 2015 Paris Agreement goals and honor the state's commitments to the United States Climate Alliance.

   The State of North Carolina will strive to accomplish the following by 2025:

   a. Reduce statewide greenhouse gas emissions to 40% below 2005 levels;
   b. Increase the number of registered, zero-emission vehicles ("ZEVs"; individually, "ZEV") to at least 80,000;
   c. Reduce energy consumption per square foot in state-owned buildings by at least 40% from fiscal year 2002-2003 levels.

2. Cabinet agencies shall evaluate the impacts of climate change on their programs and operations and integrate climate change mitigation and adaptation practices into their programs and operations. Council of State members, higher education institutions, local governments, private businesses, and other North Carolina entities are encouraged to address climate change and provide input on climate change mitigation and adaptation measures developed through the implementation of this Executive Order. Consistent with applicable law, cabinet agencies shall actively support such actions.

3. The Secretary or designee of each cabinet agency and a representative from the Governor's Office shall serve on the North Carolina Climate Change Interagency Council ("Council"), which is hereby established. The Secretary of the North Carolina Department of Environmental Quality, or the Secretary's designee, shall serve as the Council Chair. The North Carolina Department of Environmental Quality shall lead the Council by providing strategic direction, scheduling and planning Council meetings, determining the prioritization of activities, facilitating stakeholder engagement, and assisting in the implementation of pathways to achieve the goals provided in Section 1 of this Executive Order.

   The duties of the Council shall include the following:

   a. Recommend new and updated goals and actions to meaningfully address climate change;
   b. Develop, implement, and evaluate programs and activities that support statewide climate mitigation and adaptation practices;
   c. Establish workgroups, as appropriate, to assist the Council in its duties;
   d. Consider stakeholder input when developing recommendations, programs, and other actions and activities;
   e. Schedule, monitor, and provide input on the preparation and development of the plans and assessments required by this Executive Order;
   f. Review and submit to the Governor the plans and assessments required by this Executive Order.

4. The North Carolina Department of Environmental Quality ("DEQ") shall develop a North Carolina Clean Energy Plan ("Clean Energy Plan") that fosters and encourages the utilization of clean energy resources, including energy efficiency, solar, wind, energy storage, and other innovative technologies in the public and private sectors, and the integration of those resources to facilitate the development of a modern and resilient electric grid. DEQ shall collaborate with businesses, industries, power providers, technology developers, North Carolina residents, local governments, and other interested stakeholders to increase the utilization of clean energy technologies, energy efficiency measures, and clean transportation solutions. DEQ shall complete the Clean Energy Plan for the Council to submit to the Governor by October 1, 2019.

5. The North Carolina Department of Transportation ("DOT"), in coordination with DEQ, shall develop a North Carolina ZEV Plan ("ZEV Plan") designed to increase the number of registered ZEVs in the state to at least 80,000 by 2025. The ZEV Plan shall help establish interstate and intrastate ZEV corridors, coordinate and increase the installation of ZEV infrastructure, and incorporate, where appropriate, additional best practices for increasing ZEV adoption. DOT shall complete the ZEV Plan for the Council to submit to the Governor by October 1, 2019.

6. The North Carolina Department of Commerce ("DOC") and other cabinet agencies shall take actions supporting the expansion of clean energy businesses and service providers, clean technology investment, and companies with a commitment to procuring renewable energy. In addition, DOC shall develop clean energy and clean transportation workforce assessments for the Council to submit to the Governor by October 1, 2019. These assessments shall evaluate the current and projected workforce demands in North Carolina's clean energy and clean transportation sectors, assess the skills and education required for employment in those sectors, and recommend actions to help North Carolinians develop such skills and education.

7. Cabinet agencies shall prioritize ZEVs in the purchase or lease of new vehicles and shall use ZEVs for agency business travel when feasible. When ZEV use is not feasible, cabinet agencies shall prioritize cost-effective, low-emission alternatives. To support implementation of this directive, the North Carolina Department of Administration ("DOA") shall develop a North

Carolina Motor Fleet ZEV Plan ("Motor Fleet ZEV Plan") that identifies the types of trips for which a ZEV is feasible, recommends infrastructure necessary to support ZEV use, develops procurement options and strategies to increase the purchase and utilization of ZEVs, and addresses other key topics. DOA shall complete the Motor Fleet ZEV Plan and provide an accounting of each agency's ZEVs and miles driven by vehicle type for the Council to submit to the Governor by October 1, 2019, and annually thereafter.

8. Building on the energy, water, and utility use conservation measures taken pursuant to N.C. Gen. Stat. § 143-64.12(a), DEQ shall update and amend, where applicable, a Comprehensive Energy, Water, and Utility Use Conservation Program ("Comprehensive Program") by February 1, 2019, and biennially beginning December 1, 2019, to further reduce energy consumption per gross square foot in state buildings consistent with Section 1 of this Executive Order. The Comprehensive Program shall include best practices for state government building energy efficiency, training for agency staff, cost estimation methodologies, financing options, and reporting requirements for cabinet agencies. DEQ and cabinet agencies shall encourage and assist, as requested, higher education institutions, K-12 schools, and local governments in reducing energy consumption. To achieve the required energy consumption reductions:

    a. By January 15, 2019, each cabinet agency shall designate an Agency Energy Manager, who shall serve as the agency point of contact.
    b. Each cabinet agency shall develop and submit an Agency Utility Management Plan to DEQ by March 1, 2019, and biennially thereafter, and implement strategies to support the energy consumption reduction goal set forth in Section 1 of this Executive Order. DEQ shall assess the adequacy of these plans and their compliance with this Executive Order.
    c. By September 1, 2019, and annually thereafter, each cabinet agency shall submit to DEQ an Agency Utility Report detailing its utility consumption, utility costs, and progress in reducing energy consumption.
    d. DEQ shall develop an annual report that describes the Comprehensive Program and summarizes each cabinet agency's utility consumption, utility costs, and achieved reductions in energy consumption. DEQ shall complete this report for publication on its website and for the Council to submit to the Governor by February 1, 2019, and annually thereafter beginning December 1, 2019.

9. Cabinet agencies shall integrate climate adaptation and resiliency planning into their policies, programs, and operations (i) to support communities and sectors of the economy that are vulnerable to the effects of climate change and (ii) to enhance the agencies' ability to protect human life and health, property, natural and built infrastructure, cultural resources, and other public and private assets of value to North Carolinians.

    a. DEQ, with the support of cabinet agencies and informed by stakeholder engagement, shall prepare a North Carolina Climate Risk Assessment and Resiliency Plan for the Council to submit to the Governor by March 1, 2020.
    b. The Council shall support communities that are interested in assessing risks and vulnerabilities to natural and built infrastructure and in developing community-level adaptation and resiliency plans.

10. DEQ shall prepare and manage a publicly accessible Web-based portal detailing the Council's actions and the steps taken to address climate-related impacts in North Carolina. Cabinet agencies shall submit data, information, and status reports as specified by the Council to be published on the portal. In addition, DEQ shall develop, publish on the portal, and periodically update an inventory of the state's greenhouse gas emissions that, among other things, tracks emissions trends statewide by sector and identifies opportunities for additional emissions reductions.

11. By October 15, 2019, and annually thereafter, the Council shall provide to the Governor a status report on the implementation of this Executive Order.

12. This Executive Order is consistent with and does not otherwise abrogate existing state law.

13. This Order is effective October 29, 2018 and shall remain in effect until rescinded or superseded by another applicable Executive Order.

IN WITNESS WHEREOF, I have hereunto signed my name and affixed the Great Seal of the State of North Carolina at the Capitol in the City of Raleigh, this the 29th day of October, in the year of our Lord two thousand eighteen.

Roy Cooper
Governor

ATTEST:

Rodney S. Maddox
Chief Deputy Secretary of State

Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-2, Sub 1219

April 13, 2020

Exhibit JMV-TF-7

EXHIBIT JMV-TF-6: COMPARISON OF CLIMATE RISK ASSESSMENTS

Introduction

This appendix conducts a more in-depth review of Duke Energy Progress's assessment of and responses to climate-related risks in its Grid Improvement Plan. We use the ConEdison Climate Change Vulnerability Study, released in December 2019, as an exemplar, and pull in materials from the Company's application and discovery responses to characterize the Company's assessment and response.

Although the collaborative process and resulting vulnerability study serve as a "nationwide model" for resiliency planning,[1] ConEd benefitted from several unique factors that enabled it to pursue such a comprehensive approach. The Storm Hardening & Resiliency Collaborative was convened after Hurricane Sandy in 2014, at the recommendation of Commission staff, and the Collaborative honed an approach for this study over 5 years. Further, the Company had express approval for costs recovery of any climate risk vulnerability assessment projects undergone at the recommendation of the Collaborative. The increased certainty of approval and recovery may have contributed to the comprehensive, 36-month process that led to the Vulnerability Study.[2] In total, the Study estimates that climate vulnerabilities could cost ConEd up between $1.3 and $4.6 billion by 2050.[3]

The purpose of this comparison is to demonstrate, through comparison, the level of depth and analytical persuasion the ConEd vulnerability study was able to pursue through collaboration and regulatory support, and show the value that such a comprehensive climate risk approach could have to grid modernization in this proceeding. Beyond analytical complexity, the Study also

[1] Ralff-Douglas, K., (2016, September). Climate Adaptation in the Electricity Sector: Vulnerability Assessments & Resiliency Plans. *California Public Utilities Commission,* p. 5. Retrieved at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/PPD%20-%20Climate%20Adaptation%20Plans.pdf.

[2] ConEd, (2015, September). Storm Hardening and Resiliency Collaborative Phase Three Report ("Phase Three Report"). New York Public Service Commission Case 13-E-0030.

[3] Consolidated Edison Company of New York Inc. ("ConEd"), (2019, December). Climate Change Vulnerability Study ("ConEd Climate Study"). P. 4. Retrieved at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.

demonstrates a patient and expansive approach by starting with information gathering, embracing an iterative process, and including a broader set of resiliency solutions into the study, including customer-centered solutions.

In 2018, the Duke Energy Corporation published a Climate Report to Shareholders, which discusses climate-related risks at a high level and their relation to the Corporation's general strategy.[4] In correspondence, the Company indicated that the report "speaks for itself, is intended 'To provide information on Duke Energy's strategy and the steps [it] is taking to mitigate risks from climate change,'" and "Does not, and was not intended to, identify actual or potential costs for which recovery is sought in this proceeding."[5] Based on this representation, this appendix will not consider the Report to Shareholders as an analysis of climate-related risks of the Company's assets or operations.

Finally, It is also worth noting that the Company finds that helping to prevent climate change is in the public interest.[6] Presumably, this finding of public interest would extend to limiting the effects of climate change on the Company's provision of affordable rates and reliable service.

The comparison is conducted in the table below. Practices from the ConEd Vulnerability Study populate the left side of the table; practices shown by the Company will be demonstrated on the right side.

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[4] Duke Energy Corporation (2018, March). 2017 Climate Report to Shareholders. Retrieved at https://www.duke-energy.com/_/media/pdfs/our-company/shareholder-climate-report.pdf.
[5] Duke Energy Progress, LLC ("Company") Company Response to Vote Solar Data Request 1-3.
[6] Company Response to Vote Solar Data Request 1-20.

General		
Category	**ConEd Vulnerability Study**	**Duke Energy Progress Grid Improvement Plan (GIP)**
Acknowledgment of Climate-Related Risks	"Con Edison recognizes the global scientific consensus that climate change is occurring at an accelerating rate."[7] One of the purposes of the Vulnerability Study is to "develop a shared understanding of… projected climate and extreme weather for the territory."[8]	Company is "without knowledge" as to the role of climate change in relation to major storm events.[9] GIP includes "Impact of Weather Events" and "Environmental Policy" as "megatrends" but declines to confirm their relation to climate-related risks.[10]
Treatment of Uncertainty	"The exact timing and magnitude of future climate change is uncertain. To account for climate uncertainty, the Study considered a range of potential climate futures …"[11]	"It is the Company's position that the Grid Improvement Plan is designed to deal with facts as known today and reasonable predictions of future events. The Company as well as its stakeholders, are unable to say with certainty what the future impacts of climate change may or may not be."[12]
Role of Stakeholders	Climate Change Vulnerability Study emerged from a co-operative proceeding facilitated by ConEd.[13]	The Company declined discussion of climate-related risks with stakeholders,[14] despite specific requests.[15]
Climate Science	ConEd used "best available climate science," to construct an in-house,	Megatrends documentation uses a combination of news articles and

[7] ConEd Climate Study, p.4.
[8] *Ibid.* p. 11.
[9] Company Response to Vote Solar Data Request 1-6.
[10] Company Response to Vote Solar Data Request 1-12.
[11] ConEd Climate Study, p. 4.
[12] Company Response to Vote Solar Data Request 1-12.
[13] ConEd, (2015, September). Storm Hardening and Resiliency Collaborative Phase Three Report ("Phase Three Report"). New York Public Service Commission Case 13-E-0030.
[14] Direct Testimony of Company Witness Jay W. Oliver ("Oliver Direct"), Exhibit 13, page 25.
[15] *Ibid.,* Ex. 13, p. 29.

	downscaled climate model[16] and ultimately "synthesized information into metrics relating plausible effects of climate changes on operations, infrastructure, and planning."[17]	historical metrics.[18] "Implications" use a qualitative, red-yellow-green approach (See Figure 1 below).[19]
Forward-looking Analysis	Study team used a risk-based approach taking into account both likelihood and consequences of climate impacts.[20]	No forward-looking climate-related analysis propounded in application materials.
Forward-looking Strategy	Study uses an 'adaptation pathways' approach that anticipates future changes and plans a sequence of interventions.[21]	The Company "has not developed any future phases of the plan,"[22] although some potential phase two projects have been described.[23]
Solutions Selection Process	ConEdison conducted a systematic, forward-looking, asset-level risk analysis before identifying adaptation options.[24]	Company identified tools available after a high-level, qualitative review of Megatrends implications.[25]
Cost-benefit Analysis	ConEd uses a systematic benefit cost analysis (CBA) handbook, developed as a part of its distributed systems implementation plan.[26] BCA incorporates social costs and is used as a criteria in solution selection.	Company did not demonstrate a cost-benefit analysis until the Plan's investments were identified

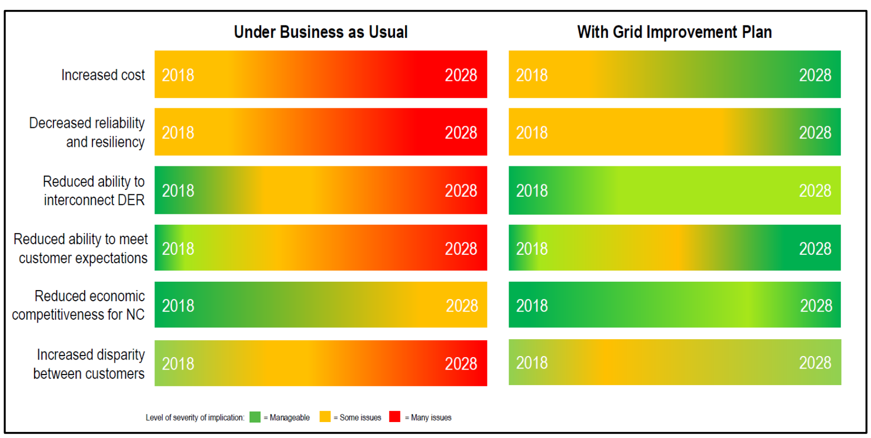
16 ConEd Climate Study, p. 18.
17 ConEd Climate Study, p. 12.
18 Oliver Direct, Ex. 2, p. 11.
19 Oliver Direct, Ex. 3, p. 10.
20 ConEd Climate Study, p. 12.
21 *Ibid*. p. 12.
22 Company Response to Vote Solar Data Request 1-22.
23 Oliver Direct, p. 47-48.
24 ConEd Climate Study, p. 14-15.
25 Oliver Direct, p. 29, ll. 18 to p. 30, ll. 18.
26 ConEd Climate Study, p. 64.

Customer Resilience Options	ConEd integrates climate resilience options for ratepayers, such as resilience hubs and DERs, into their own planning.[27]	Company did not consider customer-oriented or non-wires alternatives to address Megatrends.[28]
Sizing Investment Response	Solutions are optimized to minimize costs between societal cost of an outage and expected cost of intervention (see Figure 2, below).[29]	Company appears to not have considered different scales of Grid Improvement Plan.[30]
Specific Risks		
Temperature, Heat Index , and Heat Waves	**Worker Safety:** High heat risk days will grow from 2 days per year in historical period to 5-7 days per year by 2050 and 14-20 days per year by 2100. **Load:** Independent of other drivers, load will increase. Costs of serving incremental peak are between $1.1 and $3.1 billion by 2050.[31] **Asset Deterioration:** Higher heat stress will lead to increased deterioration, transmission line sagging, and decreased asset capacity. ConEd's incomplete estimate of the cost of deterioration is $237 to $510 million by 2050.[32]	**Worker Safety:** To our knowledge, the Company has not quantified increased worker safety risk due to heat. **Load:** The Company does not use forward-looking climate impact projection in load forecasts.[33] **Asset Deterioration:** The Company has not integrated shifts in temperature into asset deterioration. It is not clear if the Company believes that such risks are material.[34]

27 ConEd Climate Study, p. 36.
28 Company Response to Vote Solar Data Request 1-10.
29 ConEd Climate Study, p.62.
30 Company Response to Vote Solar Data Request 1-23.
31 ConEd Study, p. 42.
32 ConEd Study, p. 40-41.
33 Company Response to Vote Solar Data Requests 1-4 and 1-5.
34 Company Response to Vote Solar Data Requests 1-14 through 1-18.

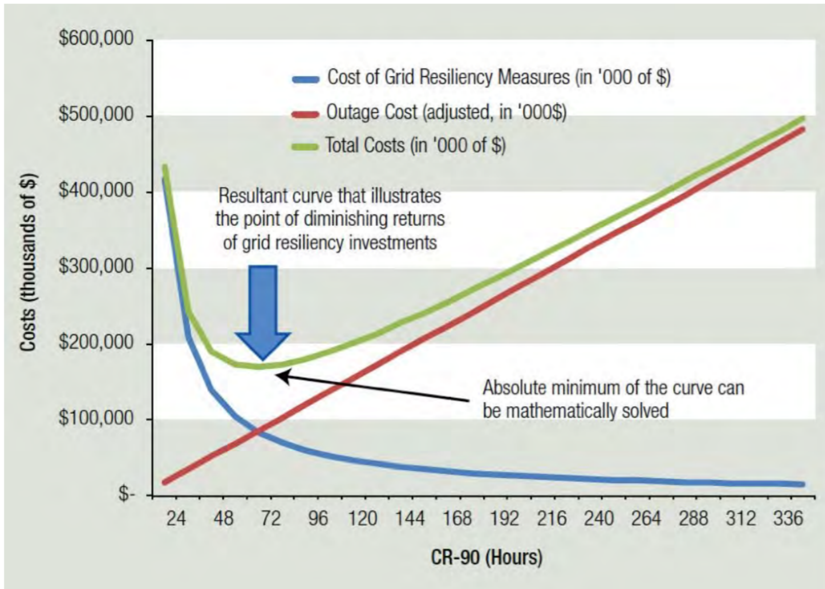
Flooding	ConEd found that sea level could exceed its current design standard (100-year floodplain plus 3 feet) between 2030 and 2080. Hardening all at-risk substations in the worst-case scenario would cost $636 million.	The Company has conducted flood risk analysis of transmission sub-stations for substations that have been flooded recently. Upgraded sub-stations will be built at a 500-year FEMA floodplain plus 1 foot (in the cases studied, this represented 0 to 1 feet higher than ConEd's 100-year plus 3 standard). No forward-looking flood risk projection was conducted.[35]
Precipitation & Extreme Weather	ConEdison described these risks qualitatively, but found assets would be more at risk due to climate change. "On an operational level, increasing frequency and intensity of extreme weather events may exceed Con Edison's currently robust emergency preparedness efforts."[36]	The Company does not factor climate change into the consideration of the frequency of major events or in determining the budget amount.[37]

Figure 1: Company's Presentation of Grid Improvement Plan Risks[38]



[35] Company Response to Vote Solar Data Request 1-11.
[36] ConEd Climate Study, p. 33.
[37] Company Response to Vote Solar Data Request 1-20.
[38] Image retrieved directly from Oliver Direct Ex. 3, p. 10.

Figure 2: Optimizing Costs of Resilience Interventions[39]



The graph above shows the total cost of investing in resiliency to outages, split between the social costs of the outage and the cost of investing in grid resiliency. CR-90 along the x-axis represents the time taken to restore power to 90% of ratepayers. The y-axis represents social costs.

Conclusion and Discussion

Clearly, ConEd and Duke Energy Progress's approaches to climate risk assessment differ at a fundamental level. ConEd's approach begins with a basic acknowledgment of the need to plan around climate risks; it gathers as much information as possible from specific climate science, stakeholders, and internal subject matter experts; then, it clearly articulates the current and future risks that face specific assets and operations, quantifying where possible. Although the full resilience plan will be published in December 2020 with the ConEd Climate Implementation plan, there are glimpses of ConEd's general bearing here: ConEd collaborated with stakeholders on its methodology for evaluating resilience solutions, and its path forward is flexible and iterative.

Duke Energy Carolinas' Progress's approach differs in key ways. The depth of information gathering, analysis and stakeholder integration in vulnerability assessment is much less robust, and as a result current and future risks to specific assets and operations are not available. Partly as a

[39] Image taken directly from ConEd Study, p. 63.

result of the lack of a analytically robust baseline, the Company did not execute an open or transparent solution selection process, and its forward implementation strategy is unclear.

The ConEd study's careful assessment of climate-related impacts on extreme weather events puts into relief the much less robust connection between Duke Energy Progress's articulated need to respond to 'increasing' weather events[40] and the Company's lack of any explicit climate-informed risk assessment in this proceeding. The Company's acknowledgement that it did not consider future flood risks,[41] despite the explicit flood hardening purpose of at least one Grid Improvement Plan project,[42] exemplifies this disconnect.

[40] Direct Testimony of Company Witness Stephen G. Demay ("DeMay Direct"), p. 6, ll. 8 and Oliver Direct, p. 26, ll. 4.
[41] See *Supra* note 35.
[42] Oliver Direct, Ex. 10, p. 22.

PUBLIC STAFF
FLOYD EXHIBIT 1

PURPA SECTION 114 [16 U.S.C. 2624]

[16 U.S.C. 2623]

SEC. 114. LIFELINE RATES.

(a) LOWER RATES.—No provision of this title prohibits a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or a nonregulated electric utility from fixing, approving, or allowing to go into effect a rate for essential needs (as defined by the State regulatory authority or by the nonregulated electric utility, as the case may be) of residential electric consumers which is lower than a rate under the standard referred to in section 111(d)(1).

(b) DETERMINATION.—If any State regulated electric utility or nonregulated electric utility does not have a lower rate as described in subsection (a) in effect two years after the date of the enactment of this Act, the State regulatory authority having ratemaking authority with respect to such State regulated electric utility or the nonregulated electric utility, as the case may be, shall determine, after an evidentiary hearing, whether such a rate should be implemented by such utility.

(c) PRIOR PROCEEDINGS.—Section 124 shall not apply to the requirements of this section.

[16 U.S.C. 2624]

SEC. 115. SPECIAL RULES FOR STANDARDS.

(a) COST OF SERVICE.—In undertaking the consideration and making the determination under section 111 with respect to the standard concerning cost of service established by section 111(d)(1), the costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determined on the basis of methods prescribed by the State regulatory authority (in the case of a State regulated electric utility) or by the electric utility (in the case of a nonregulated electric utility). Such methods shall to the maximum extent practicable—

(1) permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service and

(2) permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy components of cost. In prescribing such methods, such State regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if—

(A) additional capacity is added to meet peak demand relative to base demand; and

(B) additional kilowatt-hours of electric energy are delivered to electric consumers.

(b) TIME-OF-DAY RATES.—In undertaking the consideration and making the determination required under section 111 with respect to the standard for time-of-day rates established by section 111(d)(3) and the standard for time-based metering and communications established by section 111(d)(14), a time-of-day rate charged by an electric utility for providing electric service to each class of electric consumers shall be determined to be cost-effective with respect to each such class if the long-run benefits of such rate

Public Staff
Floyd Exhibit 2

Docket No. E-2, Sub 1219

An Evaluation of A Lifeline Rate Alternative: The Supplemental Security income Rate

RTI Economics
September 1981

E-100 VA Sub 43

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RTI ECONOMICS

Research Triangle Institute

I/A

An Evaluation of A Lifeline Rate Alternative: The Supplemental Security Income Rate

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Prepared for
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P.O. Box 991
Raleigh, North Carolina 27602

September 1981

Cooperative Agreement No. DE-FC-01-79-RG-10255/RTI Project No. 41U-2164

CONTENTS

CONTENTS (continued)

FIGURES

TABLES

TABLES (continued)

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1.0 INTRODUCTION AND SUMMARY

1.1 PROJECT BACKGROUND

The Duke Power Company's Supplemental Security Income (SSI) Rate Schedule was adopted in response to a North Carolina Utility Commission (NCUC) order issued on August 31, 1978, in Docket No. E-7, Sub 237. This order was issued approximately 8 weeks after the NCUC held a 3-day statewide "lifeline" conference in June 1978. This conference was held as one response to a resolution passed in the 1977 North Carolina General Assembly that required the NCUC to review, study, and consider the implementation of a lifeline rate for electric and gas service. Appendix A provides a detailed look at the relationship of the SSI rate to lifeline programs.

The NCUC ordered the establishment of the SSI Rate Schedule (shown in Table 1-1) as an experimental rate, initiated on the basis that this group of customers have electrical power usage characteristics that may differ substantially from those of the average residential customer. These characteristics may result in a smaller impact on utility system costs than the impact associated with the average residential customer. The rate was termed experimental in order to allow the NCUC to collect usage data on the customers to test whether or not they do have significantly different usage characteristics than the average residential customer, and to use these data to help develop a position on lifeline rates as required under the resolution in the 1977 North Carolina General Assembly. This project embraced these goals in developing its objectives and organizing its activities.

TABLE 1-1. SSI RATE DISCOUNTS[a]

Residential rate schedule	Rate (¢/month for first 350 kWh)	Maximum monthly discount ($/month)
RW (electric water heating)	2.9259	1.26
R (general service)	3.0059	.98
RA (all-electric)	3.0359	.88

[a]Effective June 16, 1980.

Several key features have influenced the overall design and execution of this project. Duke Power developed the sample design and drew the sample for the evaluation of the SSI rate discount before Research Triangle Institute (RTI) involvement in the project occurred. This was done at the request of NCUC staff, and some design considerations were ignored in order to fulfill the request in an expeditious manner.

Duke Power Company also indicated that their residential load research data were confidential and should not be released to RTI. RTI agreed to allow Duke to process and analyze the data under close supervision from the RTI project team. RTI provided Duke with computer software that facilitated Duke's efforts in processing the necessary data.

1.2 OBJECTIVES

The central objective of this study is to determine whether or not the electricity usage of customers on the SSI rate currently offered by Duke Power Company is different from the average residential customer on the Duke system in North Carolina. If SSI customer usage is different, the study will determine if the usage differences provide a cost-of-service justification for the SSI rate. A secondary objective is to assess the appropriateness of extending this rate to all low-use residential electric customers in North Carolina and the relationship of this rate to a generic lifeline rate.

1.3 SUMMARY OF RESULTS

The results of the comparative and covariance analyses employed in this study of electricity usage by SSI and non-SSI customers on the Duke Power System in North Carolina between June 1980 and March 1981 clearly showed that SSI customers used less electricity than non-SSI customers. On average, for all days and type of days, SSI customers used about half as much electricity as non-SSI customers. The differences were greatest during the winter months and smallest in the off season months, but were almost always of the same order of magnitude. When the usages of SSI and non-SSI customers were compared <u>within</u> each of the major residential customer rate classes, the differences were smaller but still significant in a large number of cases.

Even more important for purposes of rate analysis and costing is the profile of the electricity usage of SSI customers on critical system days and the load factors that characterize the shapes of the SSI electricity usage in any month. The study results demonstrate that SSI customers used less electricity (in many instances about half as much) than non-SSI customers on the system peak hours and peak days during the study period.

Monthly load factors, defined as the ratio of average to peak hourly usage for a class of customers during a month, were generally higher for SSI customers. This indicates that the load shapes of SSI customers were flatter than those of non-SSI customers. These results are less reliable than the usage results because the differences were statistically significant in only 3 months. They do, however, provide valuable information in that the load factors of SSI customers at a minimum are no worse than non-SSI customers' which suggests that the demand-related costs, and perhaps the energy costs of serving these customers, are lower.

Analysis of the customer survey results showed that there are distinct differences between SSI and non-SSI households in terms of their appliances and household characteristics. SSI customers had a lower proportion of most major electric appliances than did non-SSI customers. SSI customers tend to have smaller, less expensive homes and smaller family sizes.

The analysis of the survey data also showed that the sample means of several of the survey variables were substantially larger than the estimates of their population means due to a sampling design that oversampled larger users in each population. The effect of this was to increase the variance of the load estimates in the analyses. Sampling design limitations also precluded a direct comparison of SSI and low use non-SSI customers.

The analysis of covariance enabled a comparison of SSI and non-SSI customers by controlling for differences in appliances and other household characteristics. That is, by using a common set of covariate values (the SSI means) in both the non-SSI and SSI regressions, it was possible to attribute the resulting differences in the load estimates of non-SSI and SSI customers to behavioral differences between the two groups.

The results from the comparison for the combined rate classes in July indicated that SSI and non-SSI customers would use electricity at the same rate during the daytime but that SSI customers would use significantly less in the evening hours. One interpretation is that SSI customers are home during the day and use their discretionary appliances at those times but that non-SSI customers use theirs more intensively in the evening.

Using January's results to represent customer behavior during the heating season indicates that SSI customers would have significantly higher usage than their non-SSI counterparts during the daytime hours except during the evening and 6 a.m. to 8 a.m. when they use the same amount. SSI customers on the all electric rate used significantly more electricity at all hours of the day in January than the non-SSI customers. Likely explanations of these differences are the low penetration of wood stoves for the SSI customers, that SSI customers prefer higher indoor temperatures in the winter time, or that their homes are not as well insulated.

One important limitation in drawing inferences from the covariance analysis of the low use question is that no class of customers for rate purposes actually exists with SSI appliance profiles and non-SSI behavior. It does tell us, however, that when the effects of appliances and other household variables are controlled, there are behavioral differences between SSI and non-SSI customers and that these differences do <u>not</u> lead to lower electricity usage in all cases.

The costing analysis employed in this study focused on differences in energy costs between SSI and non-SSI customers measured in terms of both marginal and average costs. This represents a conservative estimate of the entire difference by not including differences in capital costs that could be attributed to lower SSI usage during key hours. The monthly average energy costs of SSI customers were approximately half those of non-SSI customers. Marginal energy costs of SSI customers ranged from one-third to one-half of those for the non-SSI customers.

Any final inferences for rate design that can be drawn from the results of this study require careful consideration of several important issues. It is clear from this study that SSI customers use less electricity and have lower costs than non-SSI customers. What is less clear is whether or not individuals receiving SSI payments require the implementation of an exclusive rate. There may be other subsets of residential customers who have usage patterns that are significantly different from the average residential customer and would require a special rate. If the North Carolina Utilities Commission feels that this particular class of customers should be granted special rate consideration, then there exist cost as well as social equity justifications for doing so.

2.0 SAMPLING DESIGN AND PROCEDURES

The basic purpose of Duke Power Company's SSI study is to determine if there is a cost-of-service justification for having a separate electricity rate for customers receiving Supplemental Security Income (SSI). The principal analytical objectives, therefore, involve comparisons of various usage characteristics of certain subsets of Duke Power Company's residential customers. To accomplish this objective, samples of non-SSI and SSI customers (accounts) were selected and 15-minute recording meters were installed on the selected residences. The non-SSI sample was selected from the population of N.C. residential customers having active accounts in August 1979 who:

1. Had consumed at least 1 kWh during the August 1978 billing period,
2. Had consumed at least 1 kWh during the January 1979 billing period,
3. Had consumed at least 1 kWh during the April 1979 billing period, and
4. Were not billed on the SSI rate in August 1979.

The SSI sample was selected from the population of N.C. residential customers having active accounts in August 1979 who:

1. Had consumed at least 1 kWh during the July 1978 billing period,
2. Had consumed at least 1 kWh during the January 1979 billing period,
3. Had consumed at least 1 kWh during the May 1979 billing period, and
4. Were billed according to the SSI schedule in August 1979.

The number of accounts eligible for inclusion in the sample, and the number ineligible (due to zero consumption in one or more of the prior

TABLE 2-1. CUSTOMER ACCOUNTS CONSIDERED FOR SAMPLING

Rate class	Population counts (August 1979)			
	Non-SSI customers		SSI customers	
	Eligible	Ineligible	Eligible	Ineligible
R	147,408	13,416	2,713	123
RA	198,684	18,430	421	142
RW	357,632	14,942	4,804	250
Total	703,724	46,788	7,938	515

months indicated above are shown in Table 2-1. Hence, the sampled populations constituted 93.8 percent of the 750,512 non-SSI customer accounts and 93.9 percent of the 8,453 SSI customer accounts that were classified as active in August 1979.

Each of the six rate-class-by-population categories was stratified into 64 strata by employing four usage groups during each of the three indicated months as stratification variables. For the non-SSI sample, one customer per stratum was then selected as a study participant. For the SSI sample, one customer was usually selected per stratum, though in some cases, zero, two, or three customers were selected. The overall structure of the sample design, along with the number of customers in each stratum, is shown in Tables 2-2 through 2-7. The design is highly imbalanced with respect to the numbers of customers per stratum. This feature, and the use of a single sample customer per stratum (in most cases), causes a number of analytical problems and necessitates an extensive amount of stratum collapsing for purposes of analysis.

The same sampling procedures were used by Duke for selecting the non-SSI and SSI samples. Within a given stratum, customers' data records were

TABLE 2-2. NON-SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS R

Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count	Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count
1-400	1-450	1-300	26,319	701-1400	1-450	1-300	434
		301-600	14,335			301-600	609
		601-1000	5,574			601-1000	481
		>1000	2,650			>1000	544
	451-1100	1-300	491		451-1100	1-300	693
		301-600	599			301-600	3,721
		601-1100	363			601-1000	9,973
		>1000	370			>1000	21,223
	1101-2000	1-300	23		1101-2000	1-300	61
		301-600	21			301-600	122
		601-1000	8			601-1000	359
		>1000	20			>1000	1,285
	≥2001	1-300	7		≥2001	1-300	5
		301-600	2			301-600	5
		601-1000	2			601-1000	11
		>1000	2			>1000	21
401-700	1-450	1-300	2,935	≥1401	1-450	1-300	96
		301-600	10,150			301-600	87
		601-1000	6,096			601-1000	43
		>1000	5,598			>1000	57
	451-1100	1-300	1,095		451-1100	1-300	138
		301-600	7,498			301-600	273
		601-1000	8,463			601-1000	340
		>1000	10,212			>1000	891
	1101-2000	1-300	26		1101-2000	1-300	77
		301-600	54			301-600	172
		601-1000	30			601-1000	329
		>1000	27			>1000	1,951
	≥2001	1-300	3		≥2001	1-300	11
		301-600	7			301-600	19
		601-1000	3			601-1000	33
		>1000	6			>1000	355

TABLE 2-3. NON-SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS RA

Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count	Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count
1-1800	1-900	1-1000	27,807	3001-5000	1-900	1-1000	431
		1001-1600	6,563			1001-1600	367
		1601-2500	1,108			1601-2500	331
		>2500	123			>2500	93
	901-1600	1-1000	9,809		901-1600	1-1000	3,683
		1001-1600	6,169			1001-1600	4,754
		1601-2500	2,604			1601-2500	4,697
		>2500	331			>2500	822
	1601-2500	1-1000	619		1601-2500	1-1000	5,765
		1001-1600	545			1001-1600	10,674
		1601-2500	529			1601-2500	13,709
		>2500	128			>2500	4,685
	>2500	1-1000	65		>2500	1-1000	905
		1001-1600	52			1001-1600	2,244
		1601-2500	42			1601-2500	3,796
		>2500	21			>2500	2,556
1801-3000	1-900	1-1000	5,570	>5000	1-900	1-1000	24
		1001-1600	2,784			1001-1600	19
		1601-2500	748			1001-2500	41
		>2500	69			>2500	33
	901-1600	1-1000	18,291		901-1600	1-1000	73
		1001-1600	15,227			1001-1600	108
		1601-2500	7,727			1601-2500	235
		>2500	700			>2500	134
	1601-2500	1-1000	5,527		1601-2500	1-1000	290
		1001-1600	6,889			1001-1600	590
		1601-2500	5,855			1601-2500	1,506
		>2500	1,306			>2500	1,217
	>2500	1-1000	168		>2500	1-1000	346
		1001-1600	207			1001-1600	762
		1601-2500	278			1601-2500	2,029
		>2500	129			>2500	3,775

TABLE 2-4. NON-SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS RW

Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count	Winter (Jan. 1979)	Summer (Aug. 1978)	Off-season (April 1979)	Population count
1-700	1-700	1-600	67,343	1101-1900	1-700	1-600	1,034
		601-900	20,425			601-900	878
		901-1500	10,181			901-1500	1,065
		>1500	2,005			>1500	625
	701-1300	1-600	2,693		700-1300	1-600	2,780
		601-900	2,087			601-900	10,412
		901-1500	1,456			901-1500	32,065
		>1500	536			>1500	27,349
	1301-2500	1-600	190		1301-2500	1-600	543
		601-900	92			601-900	1,157
		901-1500	91			901-1500	8,244
		>1500	121			>1500	15,329
	>2500	1-600	10		>2500	1-600	8
		601-900	2			601-900	17
		901-1500	2			901-1500	47
		>1500	4			>1500	86
701-1100	1-700	1-600	12,523	>1900	1-700	1-600	263
		601-900	16,046			601-900	113
		901-1500	10,723			901-1500	125
		>1500	2,947			>1500	83
	701-1300	1-600	8,167		701-1300	1-600	491
		601-900	30,124			601-900	493
		901-1500	34,635			901-1500	925
		>1500	14,209			>1500	1,007
	1301-2500	1-600	208		1301-2500	1-600	487
		601-900	293			601-900	611
		901-1500	354			901-1500	2,415
		>1500	236			>1500	9,746
	>2500	1-600	12		>2500	1-600	50
		601-900	13			601-900	51
		901-1500	8			901-1500	118
		>1500	5			>1500	1,274

TABLE 2-5. SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS R

Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count	Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count
1-300	1-250	1-300	803	451-600	1-250	1-300	17
		301-450	13			301-450	4
		451-600	4			451-600	4
		>600	0			>600	3
	251-500	1-300	253		251-500	1-300	43
		301-450	61			301-450	129
		451-600	4			451-600	69
		>600	1			>600	7
	501-900	1-300	26		501-900	1-300	1
		301-450	5			301-450	41
		451-600	0			451-600	64
		>600	1			>600	14
	>900	1-300	1		>900	1-300	0
		301-450	0			301-450	4
		451-600	1			451-600	6
		>600	0			>600	4
301-450	1-250	1-300	104	> 600	1-250	1-300	10
		301-450	23			301-450	3
		451-600	0			451-600	1
		>600	0			>600	4
	251-500	1-300	163		251-500	1-300	10
		301-450	256			301-450	39
		451-600	28			451-600	44
		>600	4			>600	18
	501-900	1-300	22		501-900	1-300	3
		301-450	52			301-450	23
		451-600	19			451-600	74
		>600	3			>600	140
	>900	1-300	3		>900	1-300	1
		301-450	4			301-450	3
		451-600	2			451-600	9
		>600	0			>600	65

TABLE 2-6. SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS RA

Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count	Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count
1-1500	1-1400	1-600	115	2501-4000	1-1400	1-600	8
		601-900	20			601-900	24
		901-1400	8			901-1400	34
		>1400	0			>1400	23
	1401-2500	1-600	0		1401-2500	1-600	0
		601-900	0			601-900	2
		901-1400	0			901-1400	7
		>1400	0			>1400	6
	2501-4000	1-600	0		2501-4000	1-600	0
		601-900	0			601-900	0
		901-1400	0			901-1400	1
		>1400	0			>1400	0
	>4000	1-600	0		>4000	1-600	0
		601-900	0			601-900	0
		901-1400	0			901-1400	0
		>1400	0			>1400	0
1501-2500	1-1400	1-600	43	>4000	1-1400	1-600	0
		601-900	57			601-900	0
		901-1400	39			901-1400	7
		>1400	7			>1400	7
	1401-2500	1-600	2		1401-2500	1-600	0
		601-900	0			601-900	0
		901-1400	3			901-1400	2
		>1400	2			>1400	3
	2501-4000	1-600	0		2501-4000	1-600	0
		601-900	0			601-900	0
		901-1400	0			901-1400	0
		>1400	0			>1400	1
	>4000	1-600	0		>4000	1-600	0
		601-900	0			601-900	0
		901-1400	0			901-1400	0
		>1400	0			>1400	0

TABLE 2-7. SSI POPULATION COUNTS, BY STRATUM, FOR RATE CLASS RW

Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count	Winter (Jan. 1979)	Summer (July 1978)	Off-season (May 1979)	Population count
1-500	1-450	1-350	995	801-1300	1-450	1-350	9
		351-600	428			351-600	19
		601-1000	14			601-1000	13
		>1000	1			>1000	3
	451-800	1-350	71		451-800	1-350	5
		351-600	188			351-600	107
		601-1000	10			601-1000	362
		>1000	0			>1000	23
	801-1300	1-350	7		801-1300	1-350	1
		351-600	16			351-600	20
		601-1000	2			601-1000	312
		>1000	0			>1000	89
	>1300	1-350	0		>1300	1-350	0
		351-600	1			351-600	3
		601-1000	0			601-1000	48
		>1000	0			>1000	31
501-800	1-450	1-350	90	>1300	1-450	1-350	2
		351-600	399			351-600	9
		601-1000	37			601-1000	5
		>1000	2			>1000	0
	451-800	1-350	24		451-800	1-350	0
		351-600	706			351-600	7
		601-1000	347			601-1000	22
		>1000	6			>1000	11
	801-1300	1-350	2		801-1300	1-350	0
		351-600	66			351-600	0
		601-1000	71			601-1000	33
		>1000	4			>1000	90
	>1300	1-350	0		>1300	1-350	1
		351-600	6			351-600	1
		601-1000	9			601-1000	7
		>1000	0			>1000	69

first ordered by geographical region. If N(h) customers occurred in the h^{th} stratum and if a sample (including alternates) of size n(h) was desired from this stratum, then n(h) equal-sized sets of contiguous records were identified. A random number between 1 and N(h)/n(h) was then selected in order to choose a customer from the first within-stratum set. Using a constant skip interval equal to N(h)/n(h), a customer was selected from each of the other sets. The initial household or set of households from stratum h to be included in the study was then randomly chosen (without replacement) from the n(h) customers previously selected.

Selected customers whose dwellings could not be metered or whose accounts had become inactive prior to the time of meter installation were replaced with a randomly chosen alternate from the same stratum. In addition, at any time after sample selection, selected SSI-rate customers were dropped whenever they no longer qualified for the SSI rate and were replaced with a randomly selected customer from the same stratum who was still eligible for this SSI rate.

Target numbers of customers sample to be metered were initially the following:

	Rate class			
	R	RA	RW	Total
Non-SSI	64	64	64	192
SSI	72	52	72	196

With the availability of additional meters during the fall of 1980, the SSI sample was enlarged slightly by selecting and metering some additional customers. Full implementation of the non-SSI sample metering also was not achieved until early autumn 1980.

Sample meter allocations as they existed in August 1980 for the SSI group are given in Table 2-8. The non-SSI sample consisted of one customer within each of the 64 strata for a given rate class.

TABLE 2-8. METER ALLOCATION FOR SSI SAMPLE AS OF AUGUST 1980, BY RATE CLASS AND PRIOR USAGE LEVELS

Rate class	Stratum (July 1978 kWh)	Sample count	Stratum (January 1979 kWh)	Sample count	Stratum (May 1979 kWh)	Sample count
R	1-250	16	1-300	13	1-300	16
	251-500	18	301-450	21	301-450	18
	501-900	18	451-600	16	451-600	17
	>900	14	>600	16	>600	15
RA	1-1400	38	1-1500	12	1-600	13
	1401-2500	11	1501-2500	15	601-900	11
	2501-4000	1	2501-4000	15	901-1400	13
	>4000	0	>4000	8	>1400	13
RW	1-450	18	1-500	12	1-350	15
	451-800	19	501-800	18	351-600	18
	801-1300	16	801-1300	21	601-1000	17
	>1300	14	>1300	16	>1000	17

3.0 DATA COLLECTION PROCEDURES

3.1 BACKGROUND ON SSI RATE PROGRAM ADMINISTRATION

The selection of the SSI subset of residential customers imposed a need to define the population and to develop procedures for contacting and verifying the SSI customers. Fulfilling these requirements imposed administration costs on Duke Power because the definition of customers was not available through normal billing information.

To qualify for the Duke Power Company SSI rate, an individual must be a Duke customer who is currently receiving Supplemental Security Income payments. In addition, this person must be the head of the household as defined by the Social Security Living Arrangement A in which the individual is responsible for household expenses or shares in them at least equally. To receive SSI payments, one must be either 65 years of age or older, legally blind, or disabled for a period of time expected to exceed 12 months. Further, household income cannot be greater than 125 percent of federal poverty guidelines.

As of December 1977, 139,500 adults and 4,964 children were receiving SSI payments in North Carolina. Of the adults, 65,033 were disabled and 3,200 were blind. Of the 71,267 in the entire state who would have qualified for the Duke Power Company SSI Rate on the basis of age, 83 percent were 70 or over and 28 percent had achieved or passed their 80th birthday.*

*Statistical data on North Carolina Supplemental Security Income recipients were furnished by George V. Hess of the Social Security Administration, P. O. Box 27168, Raleigh, NC 27611. Information on the Duke Power Company SSI Rate program was provided by George E. Meier, Duke Power Company, Rate Department, Charlotte, NC 28242.

During 1977, the average SSI payment for all recipients was about $100 per month. Of the total number of SSI recipients, 56 percent also collected a regular Social Security benefit averaging $124 per month and 13 percent had unearned income, other than Social Security, averaging $40 per month. Approximately 4 percent reported an earned income of at least $94 per month.

Eighty-six percent of all SSI recipients owned their homes. Eleven percent were members of another household, and the remaining three percent lived in Medicaid institutions. With regard to sex and race, approximately 64 percent were women and 51 percent were white and 43 percent black. Other races accounted for 1.5 percent with the remainder not reported.

In January of 1979 when the SSI rate was initiated, approximately 50,000 individuals living in the 37 counties of the Duke service area were identified as receiving SSI payments. The potential SSI rate population is somewhat less than this figure because a number of households within the Duke territory are served by municipalities and rural cooperatives. From January 1979 to February 1980, Duke received approximately 11,000 applications for the rate. Some 9,400 of these have qualified, and, as of February 1980, there were about 8,600 on the rate. Enrollment has remained fairly stable around this number.

At the origination of the SSI rate program, the Social Security Administration mailed application forms to SSI recipients living in the 37 counties of the Duke service area. With the Social Security Administration responsible for this initial contact, the SSI recipients' right to remain anonymous was not violated. Upon receipt of an application form, it became the individual's responsibility to complete and return the form to a local Duke Power office.

Procedures for contacting new SSI recipients were initiated by the North Carolina Department of Human Resources in June 1979. These procedures entail a periodic mailing of application forms to be completed and returned to Duke Power by the individual. Approximately 1,000 new recipients have been contacted each month in this effort.

To monitor the eligibility of those who receive billing on the SSI rate, Duke periodically prepares a computer tape containing their names and forwards this tape to the Department of Human Resources. There it is compared with a tape containing the names of all SSI recipients in North Carolina. An exceptions list of those who receive SSI rate billing but do not receive SSI assistance is then returned to Duke. Accounts on this list are reassigned by Duke to the appropriate residential rate schedule.

3.2 LOAD RESEARCH DATA

Duke Power Company provided 192 Westinghouse single-phase meters with two-channel recorders to record the pulse data in 15-minute intervals for the SSI sample customers. The control group customers were metered as part of Duke's Residential Load Research Program.

By January of 1980, Duke had installed the 192 recorders on the SSI sample customers. Duke changed its load research sample in March 1980 and did not have the meters in place on the new sample until June 1980. Recorded load data for this project were available for analysis from June 1980 through March 1981.

This standard load research practice at Duke of obtaining only 10 months of actual load data limited the data collection of the project. RTI project team members urged Duke to change its program to acquire a full year's data for future load analyses. Duke has subsequently resolved the difficulties that caused this problem and are conducting their load research programs are being conducted over the entire year.

Duke's metering department changed the recording cartridges on a monthly basis. They dispatched these tapes monthly to the central office for translation on a Westinghouse translater. Data from the translater were transferred to a computer-readable tape and analyzed in the Duke Load Research Department.

RTI and Duke developed procedures for providing summary information on data collection and reduction procedures to ensure the highest possible quality for the analysis. Appendix B provides details on Duke's data translation procedures.

3.3 CUSTOMER SURVEY DATA

The customer survey data provide detailed information on household characteristics and socioeconomic characteristics of the sample customers. Duke Power Company's marketing representatives acquired these data through personal interviews with each of the customers. Data on age of house and present market value of the house for the SSI customers were estimated by the representatives in a subsequent effort to provide consistent measures for both the control and experimental customers. The survey instruments used for acquiring data on both groups of customers are presented in Appendix C.

3.4 SYSTEM LOAD DATA

Table 3-1 presents a summary of the Duke Power Company system load data for the study period. The table provides summary statistics on the day, hour, and size of the monthly system peak and also the load factor of the system. The data are summarized from the actual operating data of the Duke Power Company system.

TABLE 3-1. SYSTEM LOAD CHARACTERISTICS

Month/year	Day	Hour	Monthly system peak (megawatt h)	Load factor
June 1980	8	18	8,784	.688
July 1980	16	15	10,364	.669
August 1980	6	18	10,239	.699
September 1980	3	15	9,590	.688
October 1980	30	19	7,835	.750
November 1980	20	8	9,038	.682
December 1980	4	8	9,068	.721
January 1981	12	8	10,530	.691
February 1981	4	8	10,395	.660
March 1981	19	20	9,086	.698

4.0 COMPARATIVE ANALYSIS OF LOAD RESEARCH DATA

Installation of recording meters on sample customers with and without the SSI rate was completed in June 1980. Monitoring of 15-minute kWh consumption continued on all sample customers through March 1981. Thus, 15-minute kWh consumption data were available for analysis for most sample customers over a 10-month period: June 1980 through March 1981. These data formed the basis for the comparative analyses described in this section.

The objectives of the comparative analyses are the following:

- To provide statistical estimates of various electricity consumption characteristics of the SSI-rate and non-SSI-rate residential customer populations;
- To make statistical comparisons of these populations with respect to the various usage characteristics;
- To provide such estimates and comparisons for each of the three basic rate classes:

  R = general residential service

  RA = all-electric residential service

  RW = water heating residential service.

The statistical inferences are made for the Duke Power Company North Carolina service territory as of the time of sampling (August 1979). The estimates/comparisons, however, must be treated with some caution, since the methodology involves a number of assumptions necessitated principally because of the sample design limitations and because of the lack of sufficient information on population dynamics during the study period.

4.1 DESCRIPTION OF ANALYSIS VARIABLES

The time frame for analyzing the 15-minute usage data is a calendar month. Therefore, all analyses are repeated for each of 10 months--June 1980 through March 1981. The parameters that were estimated for each month are identified in Table 4-1. These parameters were estimated for seven subsets of days within the month (day of system peak, weekdays, weekend days, all days, and days in which the system load exceeded 80 percent, 90 percent, or 95 percent of the annual system peak) for the population of North Carolina residential customers on the SSI rate and for the population not on the SSI rate. Corresponding parameters of each population were compared, via statistical tests, to determine if there were statistically significant differences in the usage patterns. Procedures for estimating the parameters and performing the statistical tests are given in Appendix D.

The first 24 parameters listed in Table 4-1 correspond to average hourly consumption values (for each of the 24 hours of the day) for the various subsets of days. Parameter 25 is the average daily kWh (or the sum of parameters 1-24). Parameters 26 and 27 are, respectively, the average 60-minute and 15-minute noncoincident demands. The 28th parameter is the class load factor based on the demand at the time of system peak. This parameter is estimated only for the day of system peak and for the month (i.e., all days). The last parameter is the estimated average hourly consumption over hours with "high" system load, using three alternative definitions of "high." In all, 194 parameters per month are estimated for each of the two populations. Similar estimates are determined by rate class (R, RA, RW).

TABLE 4-1. LIST OF PARAMETERS ESTIMATED FOR SPECIFIC SUBSETS OF DAYS IN CALENDAR MONTHS JUNE 1980 - MARCH 1981

Parameters[a]	Day of system peak	Weekdays	Weekend days	All days	Days with system load exceeding: 80 percent of annual peak	90 percent of annual peak	95 percent of annual peak
1. Average kWh in 0000-0100							
2. Average kWh in 0100-0200							
3. Average kWh in 0200-0300							
4. Average kWh in 0300-0400							
5. Average kWh in 0400-0500							
6. Average kWh in 0500-0600							
7. Average kWh in 0600-0700							
8. Average kWh in 0700-0800							
9. Average kWh in 0800-0900							
10. Average kWh in 0900-1000							
11. Average kWh in 1000-1100							
12. Average kWh in 1100-1200							
13. Average kWh in 1200-1300							
14. Average kWh in 1300-1400							
15. Average kWh in 1400-1500							
16. Average kWh in 1500-1600							
17. Average kWh in 1600-1700							
18. Average kWh in 1700-1800							
19. Average kWh in 1800-1900							
20. Average kWh in 1900-2000							
21. Average kWh in 2000-2100							
22. Average kWh in 2100-2200							
23. Average kWh in 2200-2300							
24. Average kWh in 2300-2400							
25. Average daily kWh							
26. Average 60-min noncoincident max demand							
27. Average 15-min noncoincident max demand							
28. Class load factor (based on demand at time of system peak)		N/A	N/A		N/A	N/A	N/A
29. Average hourly kWh during critical hours[b]	N/A	N/A	N/A	N/A	(1)	(2)	(3)

[a]Estimated on a per customer basis.

[b](1) Critical hours = hours with system load over 80 percent of annual system peak.
(2) Critical hours = hours with system load over 90 percent of annual system peak.
(3) Critical hours = hours with system load over 95 percent of annual system peak.

NA = not applicable.

4.2 DATA COMPILATION, REDUCTION, AND ANALYSIS PROCEDURES

The overall structure of the analysis process for the Duke SSI Rate Study involved four major data processing/analysis steps:

1. Creation of Billing Month Usage Files (BMUFs) from the raw data tapes;
2. Creation of Calendar Month Usage Files (CMUFs) from the BMUFs;
3. Data editing and creation of Analysis Files from the CMUFs;
4. Statistical analyses.

The initial raw data tapes contained 15-minute billing month data in the form of one record per customer per day for the period June 1980 through March 1981. In creating the Billing Month Usage Files, pulse counts were converted to 15-minute kWh values and the data were screened for duplicate records, data gaps, and overlaps with records from prior billing months.

After splicing together the start and stop days from consecutive billing months, the 15-minute usage records were split into the appropriate Calendar Month Usage Files, which contained one record per customer per day. In the next processing step, the 15-minute usage data were first aggregated to produce hourly usage data. Any missing 15-minute value within a particular hour was assumed to generate a missing value for the entire hour. The data for each customer were then aggregated to produce a data file containing average hourly usage values over the seven different time frames within each calendar month (see Table 4-1). During this stage of the processing, customers for whom large amounts of data were missing in a given month were excluded from further analysis. In addition, customers with unusual data patterns were identified for further manual examination; if warranted, such customers' data were also excluded (on a month-by-month basis). Table 4-2 shows, by month and rate class, the number of non-SSI and SSI customers who were

TABLE 4-2. SAMPLE SIZES AND NUMBER OF SAMPLE EXCLUSIONS, BY MONTH, RATE CLASS, AND POPULATION

Population	Month	Number of sample customers								
		Providing some kWh data[a]			Excluded in editing[b]			Providing valid usage data[c]		
		R	RA	RW	R	RA	RW	R	RA	RW
Non-SSI-customers	June 1980	44	49	50	7	11	12	37	38	38
	July	51	50	51	11	11	7	40	39	44
	August	54	52	52	8	15	9	46	37	43
	September	57	54	54	8	16	10	49	38	44
	October	59	59	58	13	9	16	46	50	42
	November	57	62	61	9	5	16	48	57	45
	December	57	63	62	7	6	17	50	57	45
	January 1981	59	63	49	16	4	12	43	59	47
	February	55	64	62	9	11	15	46	53	47
	March	58	64	59	10	13	7	48	51	52
SSI-customers	June 1980	73	53	69	24	11	15	49	42	54
	July	65	53	63	19	8	13	46	45	50
	August	62	57	62	15	15	10	47	42	52
	September	66	57	65	18	12	14	48	45	51
	October	67	56	67	15	17	15	52	39	52
	November	69	57	68	13	13	15	56	44	53
	December	74	58	71	13	12	13	61	46	58
	January 1981	75	55	70	14	8	11	61	47	59
	February	75	54	68	14	9	11	61	45	57
	March	73	54	67	11	12	11	62	42	56

[a]These totals exclude those customers with no data during the calendar month.

[b]Customers were excluded automatically if they had excessive amounts of missing data during the calendar month. Other customers were excluded if erroneous data were suspected or if the assigned rate schedule (e.g., SSI-R) was no longer appropriate.

[c]These sample sizes apply to those response variables associated with the weekend, weekday, or all-day time frames; for other time frames (e.g., day of system peak), the sample sizes may be slightly smaller than those shown here.

excluded by the statistical editing procedures, and the number providing valid usage data. The latter are the sample sizes used in the analyses for the R, RW, and RA rate classes (Section 4.4). Table 4-3 provides the same information as Table 4-2 after aggregating over these three rate classes.

The final step in creating the analysis variables involved examination of the sample sizes after data editing to determine if the number of customers providing data in each population/stratum combination was sufficient for estimating the desired parameters and their standard errors. Such estimation requires the assumption that, within each stratum and population, the final sample of respondents constitutes a random sample from the corresponding stratum of the particular population. Estimation of the standard errors also requires the availability of data from at least two customers per population per stratum. These requirements necessitated collapsing a large number of strata into single strata, since the sample design usually called for the selection of only one (or in some cases, two or three) customer per stratum.

In order to perform the analyses, the prior usage strata were collapsed in accordance with the season for which analyses were being performed. For example, for analyzing data from June, July, August, or September, prior summertime usage strata, within rate classes, were employed. Similarly, winter-month usage variables were analyzed using the prior wintertime usage strata (within rate classes). Table 4-4 identifies the particular stratification used in each of the monthly analyses as well as the number of customers in each such stratum. These counts indicate the weights attached to the strata means that were used to produce an overall estimated mean.

TABLE 4-3. SAMPLE SIZES AND NUMBER OF SAMPLE EXCLUSIONS, BY MONTH AND POPULATIONS[a]

Month	No. of sample customers providing some usage data		No. of sample customers excluded in editing		No. of sample customers with valid usage data	
	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI
June 1980	143	195	30	50	113	145
July	152	181	29	40	123	141
August	158	181	32	40	126	141
September	165	188	34	44	131	144
October	176	190	38	47	138	143
November	180	194	30	41	150	153
December	182	203	30	38	152	165
January 1981	181	200	32	33	149	167
February	181	197	35	34	146	163
March	181	194	30	34	151	160

[a]Since entries in this table are obtained from Table 4-2 by adding over rate classes, the footnotes of Table 4-2 apply to this table as well.

I/A

TABLE 4-4. POPULATION COUNTS OF SSI AND NON-SSI CUSTOMERS, BY STRATA

SSI population rate class	June-September analyses		October-November analyses		December-March analyses	
	Stratum (July 1978 usage)	Population count	Stratum (January 1979 usage)	Population count	Stratum (May 1979 usage)	Population count
R	1-250	993	1-300	1,173	1-300	1,460
	251-500	1,129	301-450	683	301-450	660
	501-900	488	451-600	410	451-600	329
	>900	103	>600	447	>600	264
RA	1-1,400	392	1-1,500	143	1-600	168
	>1,400	29	1,501-2,500	153	601-900	103
			2,501-4,000	105	901-1,400	101
			>4,000	20	>1,400	49
RW	1-450	2,026	1-500	1,733	1-350	1,207
	451-800	1,889	501-800	1,769	351-600	1,976
	801-1,300	713	801-1,300	1,045	601-1,000	1,292
	>1,300	176	>1,300	257	>1,000	329
Non-SSI population rate class	**Stratum (Aug. 1978 usage)**	**Population count**	**Stratum (January 1979 usage)**	**Population count**	**Stratum (Apr. 1979 usage)**	**Population count**
R	1-450	76,008	1-400	50,786	1-300	32,414
	451-1,100	66,343	401-700	52,203	301-600	37,674
	1,101-2,000	4,565	701-1,400	39,547	601-1,000	32,108
	>2,000	492	>1,400	4,872	>1,000	45,212
RA	1-900	46,111	1-1,800	56,515	1-1,000	79,373
	901-1,600	75,364	1,801-3,000	71,475	1,001-1,600	57,954
	1,601-2,500	59,834	3,001-5,000	59,512	1,601-2,500	45,235
	>2,500	17,375	>5,000	11,182	>2,500	16,122
RW	1-700	146,379	1-700	107,238	1-600	96,802
	701-1,300	169,429	701-1,100	130,503	601-900	82,814
	1,301-2,500	40,117	1,101-1,900	101,639	901-1,500	102,454
	>2,500	1,707	>1,900	18,252	>1,500	75,562

With this assumption, which also involves an implicit nonresponse adjustment, a mean kWh (e.g., for a given hour or day) for the SSI population can be estimated by a weighted sum of strata means. For example, if Y_{hi} denotes the value of the particular kWh variable for the i^{th} sample member of the h^{th} SSI stratum, and if there are n_h sample customers providing values of Y_{hi}, then the particular stratum mean is estimated as

$$\hat{\bar{Y}}_h = \sum_{i=1}^{n_h} Y_{hi}/n_h \quad .$$

These means are then weighted according to the population counts N_h (as shown in Table 4-4) to produce an overall estimate for the SSI population:

$$\hat{\bar{Y}} = \sum_{h=1}^{H} N_h \bar{Y}_h / N$$

where

H = number of (collapsed) strata, and

$N = \sum_{h=1}^{H} N_h$ = total number of SSI customers.

The standard error of $\bar{Y}$ is estimated by taking the square root of

$$\mathrm{Var}[\hat{\bar{Y}}] = \left(\frac{1}{N}\right)^2 \sum_{h=1}^{H} \frac{s_h^2}{n_h} \left(N_h - n_h\right) N_h \quad ,$$

where

$$s_h^2 = \left(\sum_{h=1}^{n_h} Y_{hi} - \hat{\bar{Y}}_h\right)^2 \Bigg/ \left(n_h - 1\right)$$

= variance of the Y_{hi} responses among the n_h sample customers in the h^{th} stratum.

Similar formulas are used to estimate the corresponding mean of the non-SSI population and the standard error of the estimate. If $\hat{\bar{X}}$ denotes this estimated non-SSI mean, then comparisons between the two true population means $\overline{X}$ and $\overline{Y}$, can be made using the test statistic

$$t = \left(\hat{\overline{X}} - \hat{\overline{Y}}\right) / [\mathrm{Var}(\hat{\overline{X}}) + \mathrm{Var}(\hat{\overline{Y}})]^{\frac{1}{2}} \ .$$

Under the assumption that $\hat{\overline{X}}$ and $\hat{\overline{Y}}$ are approximately normally distributed with a common mean (the null hypothesis), this statistic will for large samples be approximately normally distributed with a zero mean. Hence, t can be used to provide an approximate test for differences in the population means.

4.3 OVERALL COMPARATIVE ANALYSIS RESULTS

A major objective of this study was to determine if, and to what extent, electricity usage patterns for SSI-rate customers differ from load patterns of customers not on the SSI rate. To achieve this objective, 15-minute kWh recording meters were used to monitor electricity usage on two samples of Duke's North Carolina residential customers--those with and those without the SSI rate (as of August 1979). This section describes the results of various analyses that were conducted to make this comparison of the load characteristics of the two populations.

The general analytical approach involved estimating certain parameters or load characteristics for the two populations, as indicated in Section 4.2, and then comparing these estimates, via statistical tests, to determine whether the difference could reasonably be attributed to chance or whether the difference was due to inherent differences in the populations with respect to the usage of electricity. The parameters estimated for each population in each calendar month were identified in Table 4-1.

Comparative analysis results for the day of system peak and hours of high system load in the months of June 1980 through March 1981 are given in

Section 4.3.1. Similarly, comparative analysis results for the average day for these calendar months are presented in Section 4.3.2. The next subsection presents monthly class load factors and the final subsection discusses usage patterns for the two groups during weekdays and weekend days. Detailed comparisons of the data summarized herein will be presented in a companion volume to this report.

4.3.1 Days and Hours of High System Load

Table 4-5 presents, for the day of monthly system peak, the percentage differences in electricity consumption for the populations of customers having and not having the SSI rate. Differences in consumption are expressed in terms of percentages relative to the population that was not on the SSI rate.

It is evident from the results given in Table 4-5 that customers on the SSI rate used significantly less electricity than those on the regular R, RA, or RW rates. For example, on the day in which the system peaked in January 1981, the daily difference in consumption (parameter 25) reached 58.5 percent. Similar, though somewhat smaller, differences in daily consumption were observed for the days of system peak in each of the other months. These daily differences reflect lower consumption by customers on the SSI rate throughout the 24-hour day (parameters 1-24); however, the largest percentage differences in the two populations generally appeared to occur during evening, nighttime, and early morning hours (from about 6 p.m. to 8 a.m.). The most pronounced differences appeared in the wintertime during early morning hours (midnight to 8 a.m.).

Both the 15- and 60-minute noncoincident maximum demands (parameters 26 and 27) for days of monthly system peak were significantly lower during all months of the study for the population of SSI-rate customers. The percent-

TABLE 4-5. COMPARISON OF AVERAGE USAGE PATTERNS OF NON-SSI AND SSI CUSTOMERS ON DAYS OF MONTHLY SYSTEM PEAKS, BY MONTH

Parameter	Percentage differences, by month[a]									
	1980							1981		
	Jun. 3	Jul. 16	Aug. 6	Sept. 3	Oct. 30	Nov. 20	Dec. 4	Jan. 12	Feb. 4	Mar. 19
1. Average kWh in 0000-0100	53.6	52.8	54.6	46.9	41.5	66.5	62.6	62.7	61.5	40.0
2. Average kWh in 0100-0200	44.3	44.4	45.7	45.3	41.7	66.8	58.0	64.0	63.4	48.2
3. Average kWh in 0200-0300	41.3	44.5	47.5	45.7	46.4	64.9	62.9	64.8	68.4	53.8
4. Average kWh in 0300-0400	50.3	40.5	46.6	40.4	45.3	65.0	59.0	65.2	66.6	52.8
5. Average kWh in 0400-0500	46.8	41.6	39.6	29.4	47.8	60.8	60.9	64.5	66.2	46.8
6. Average kWh in 0500-0600	43.7	42.7	41.5	42.6	53.5	68.0	58.9	67.2	67.6	50.0
7. Average kWh in 0600-0700	47.6	48.7	45.9	48.0	50.1	64.2	64.1	68.0	65.8	59.1
8. Average kWh in 0700-0800	48.9	45.5	52.0	43.4	34.8	61.3[b]	59.3[b]	61.9[b]	60.0[b]	53.9
9. Average kWh in 0800-0900	(23.6)	33.2	43.6	(29.7)	33.8	44.1	46.6	48.3	57.4	32.9
10. Average kWh in 0900-1000	(19.5)	(27.8)	49.2	(27.2)	(27.7)	40.9	43.5	50.6	50.3	36.9
11. Average kWh in 1000-1100	(17.1)	34.1	37.3	39.6	30.7	43.6	49.6	55.1	50.1	37.3
12. Average kWh in 1100-1200	(27.2)	44.1	39.6	34.5	38.8	44.7	42.6	46.6	43.3	41.9
13. Average kWh in 1200-1300	42.0	52.5	43.0	35.0	39.4	44.8	49.2	53.3	49.1	42.8
14. Average kWh in 1300-1400	42.9	54.9	41.2	39.6	48.7	49.3	57.2	53.2	45.9	50.6
15. Average kWh in 1400-1500	49.1	50.2[b]	44.7	37.3[b]	44.5	32.1	48.1	56.2	47.0	45.8
16. Average kWh in 1500-1600	35.9	47.5	44.8	39.8	39.3	35.7	41.5	51.7	41.0	40 1
17. Average kWh in 1600-1700	43.4	46.5	44.0	55.0	40.7	39.0	41.9	47.1	48.5	(25.7)
18. Average kWh in 1700-1800	49.7[b]	48.9	40.6[b]	53.6	41.9	54.6	50.4	55.5	51.2	40.3
19. Average kWh in 1800-1900	55.1	53.3	54.0	53.7	55.4[b]	56.1	53.8	59.1	53.1	54.8
20. Average kWh in 1900-2000	58.3	54.4	57.7	51.7	50.1	56.0	57.2	56.3	58.9	53.6
21. Average kWh in 2000-2100	57.6	59.7	55.6	39.3	60.0	61.1	58.8	60.0	55.9	56.6[b]
22. Average kWh in 2100-2200	53.7	57.7	49.3	54.3	60.4	61.9	63.6	60.6	61.3	58.9
23. Average kWh in 2200-2300	57.1	61.4	56.0	55.5	58.2	64.7	63.8	64.0	62.6	55.0
24. Average kWh in 2300-2400	59.4	57.7	51.1	55.8	52.5	62.5	62.8	64.9	60.1	49.9
25. Average daily kWh	46.8	49.4	47.5	44.7	45.6	55.5	55.5	58.5	57.0	47.8
26. Average 60-min noncoincident max demand	45.1	46.9	45.5	42.4	44.2	50.2	51.3	50.3	47.7	43.9
27. Average 15-min noncoincident max demand	36.5	40.3	39.0	34.9	41.1	46.3	44.2	46.2	41.0	39.9

[a]Percentage differences are calculated relative to the non-SSI population. Differences which are not statistically significant at the .01 level are shown in parentheses.

[b]Indicates hour of system peak.

age differences in these parameter estimates appeared most pronounced in the winter months--perhaps due to the disproportionately small number of all-electric customers in the SSI population (5 percent) as compared to the non-SSI population (28 percent).

The levels of consumption used in calculating the percentage differences shown in Table 4-5 will be given in a companion volume to this report.

Table 4-6 shows, for each month of the study period, the average electricity consumption (in watthours per customer per hour) over four subsets of hours, listed below.

Type of hour	Definition
1	Hour of system peak in the month
2	All hours in the month in which system load exceeded 95 percent of the annual system peak (10,530 MWh on January 12, 1981 at 7-8 a.m.)
3	All hours in the month in which system load exceeded 90 percent of the annual system peak
4	All hours in the month in which system load exceeded 80 percent of the annual system peak

The upper portion of the table shows the number of hours involved in the average, and the lower portion of the table gives the percent difference in the SSI and non-SSI consumption levels during the particular set of hours. All of the differences shown are statistically significant and most are around 50 percent, indicating that the SSI customers used about half as much electricity during these types of hours as did the non-SSI customers.

4.3.2 Average Day of the Month

In contrast to the previous section, which focused on consumption during the days and hours of a calendar month in which the system load was high, this section discusses consumption averaged over all days of the calendar month.

TABLE 4-6. COMPARISON OF SSI AND NON-SSI CUSTOMERS WITH RESPECT TO ELECTRICITY CONSUMPTION DURING HOURS OF HIGH SYSTEM LOAD

	Type of hour*	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
Number hours:											
	1	1	1	1	1	1	1	1	1	1	1
	2	0	20	39	0	0	-	-	8	7	
	3	0	59	96	15	0	-	-	22	17	
	4	20	216	227	100	0	15	25	131	84	11
Average consumption per hour (watt hours):											
Non-SSI	1	1,845	2,038	2,438	1,572	2,174	3,159	2,968	3,460	3,175	2,401
SSI	1	928	1,014	1,447	986	969	1,221	1,208	1,320	1,271	1,042
Non-SSI	2	-	2,278	2,215	-	-	-	-	2,931	3,006	-
SSI	2	-	1,163	1,163	-	-	-	-	1,314	1,274	-
Non-SSI	3	-	2,155	2,145	1,874	-	-	-	2,793	2,671	-
SSI	3	-	1,117	1,118	968	-	-	-	1,271	1,249	-
Non-SSI	4	1,663	1,936	1,986	1,726	-	2,574	2,516	2,457	2,500	2,353
SSI	4	861	1,012	1,043	908	-	1,214	1,210	1,163	1,111	1,160
Percent difference:											
	1	49.7	50.2	40.6	37.3	55.4	61.3	59.3	61.9	60.0	56.6
	2	-	48.9	47.5	-	-	-	-	55.2	57.6	-
	3	-	48.2	47.9	48.4	-	-	-	54.5	53.2	-
	4	48.2	47.7	47.5	47.4	-	52.8	51.9	52.7	55.6	50.7

*1 = Hour of system peak in the month.
2 = All hours in the month in which system load exceeded 95 percent of the annual system peak (10,530 MWh on January 12, 1981, at 7-8 a.m.).
3 = All hours in the month in which system load exceeded 90 percent of the annual system peak.
4 = All hours in the month in which system load exceeded 80 percent of the annual system peak.

Table 4-7 summarizes, by month, differences in electricity consumption for the two populations of interest. Differences in consumption are expressed in terms of percentages relative to the non-SSI population.

It is obvious from the information given in Table 4-7 that the SSI customers used substantially less electricity than those who did not have the SSI rate. For the average day in January 1981, for instance, SSI customers consumed 54.4 percent less electricity (see parameter 25 for January in Table 4-7). Similar results were observed for the average day in November December, and February. During the warm-weather months, the percentage differences were slightly smaller (43 to 48 percent) but still highly significant. In August, for example, the average daily consumption for the SSI customers was 46.4 percent lower than that for the non-SSI population.

The average daily difference reflects a lower consumption by SSI customers throughout the 24-hour day (parameters 1-24 in Table 4-7). This is best illustrated by examining average daily load curves for the two populations. Figures 4-1 and 4-2 show these estimated load curves for August 1980 and January 1981, respectively.

4.3.3 Monthly Class Load Factors

Two types of monthly class load factors (MCLF) were estimated for the SSI and non-SSI customer populations:

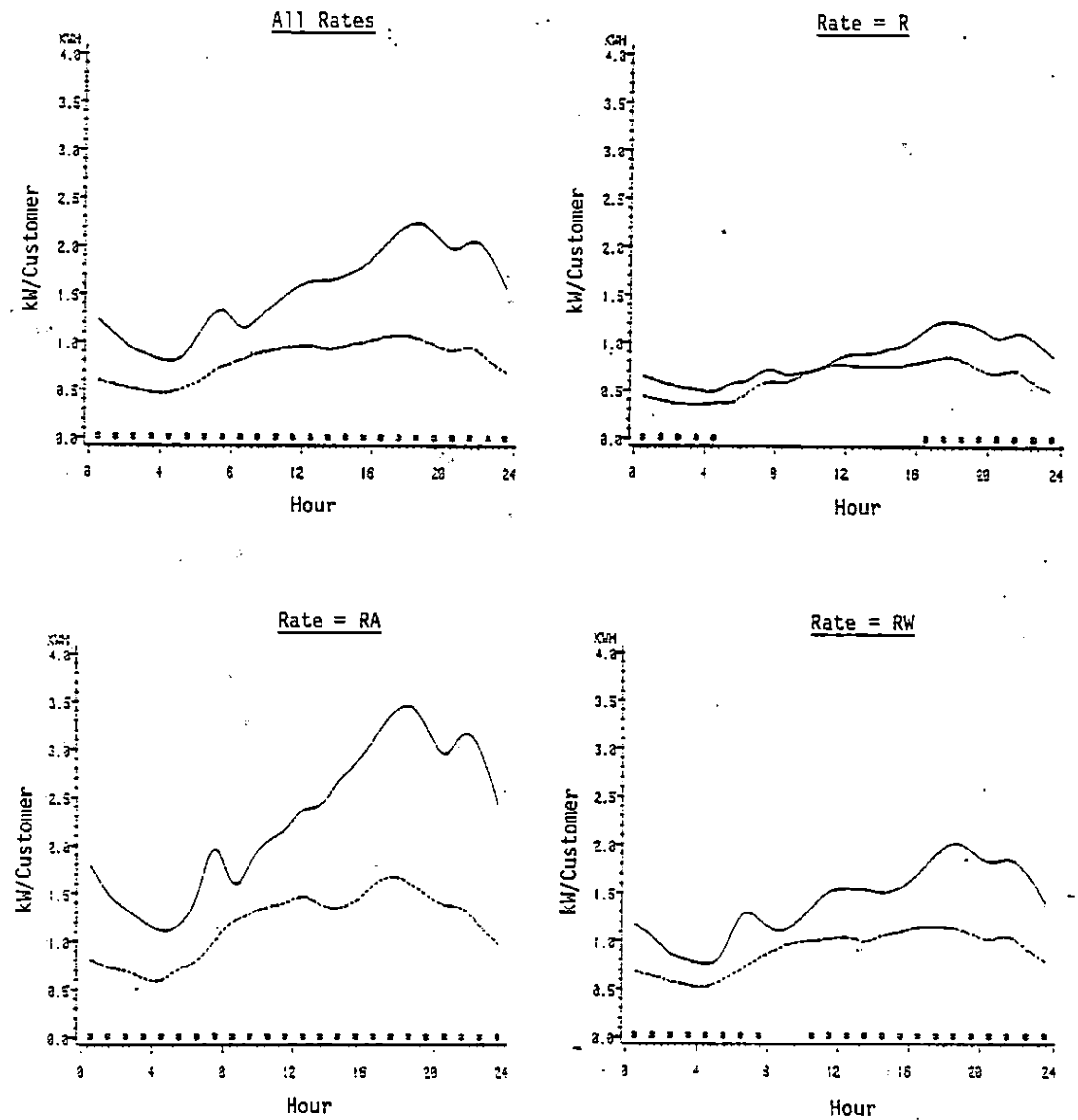
1. MCLF based on usage at time of monthly system peak; and
2. MCLF based on usage at time of monthly class peak.

Statistical comparisons between the two groups are carried out only for the first type of MCLF, since the second type is a parameter that is defined only at the class level and, consequently, a parameter for which appropriate variance estimates cannot be determined from a single sample of a given

TABLE 4-7. COMPARISON OF AVERAGE DAILY USAGE PATTERNS OF NON-SSI AND SSI POPULATIONS, BY MONTH

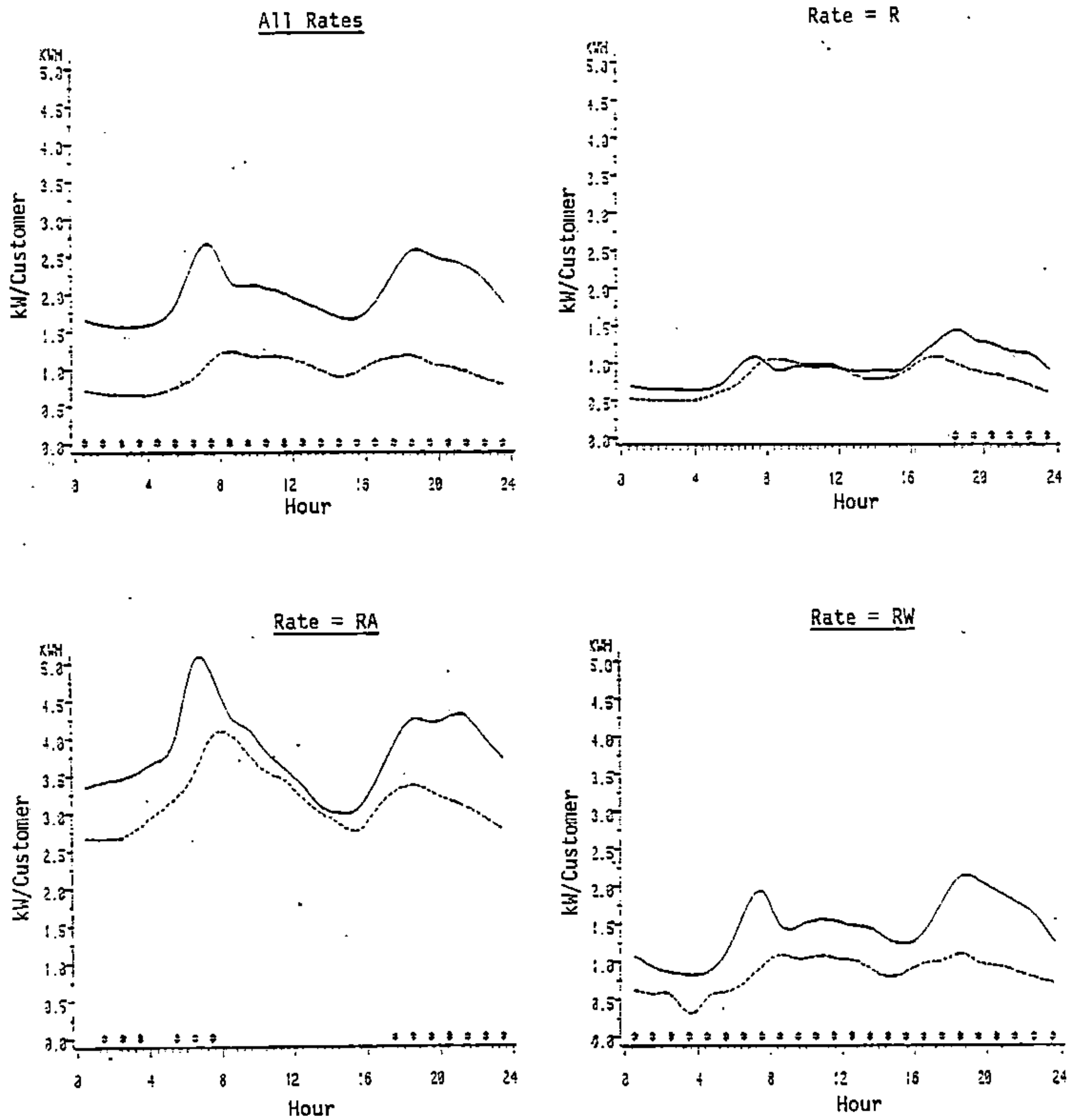
	Percentage differences, by month[a]									
	1980							1981		
Parameter	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.
1. Average kWh in 0000-0100	46.8	53.0	48.2	43.7	44.1	58.3	59.5	58.3	57.8	49.3
2. Average kWh in 0100-0200	43.1	49.3	45.9	40.5	44.3	56.3	58.6	58.8	58.9	52.3
3. Average kWh in 0200-0300	41.3	46.0	45.0	38.2	42.8	56.4	58.2	59.4	60.6	53.3
4. Average kWh in 0300-0400	42.4	45.1	41.0	37.4	43.8	57.5	59.3	59.9	60.5	55.2
5. Average kWh in 0400-0500	39.0	42.2	36.3	30.6	43.1	58.8	60.6	59.9	60.2	55.1
6. Average kWh in 0500-0600	43.4	41.5	40.2	37.6	51.5	60.3	61.2	60.3	61.7	58.0
7. Average kWh in 0600-0700	48.0	45.0	47.0	46.0	49.3	58.0	62.2	63.8	62.8	58.6
8. Average kWh in 0700-0800	39.7	41.9	40.3	40.0	40.8	49.5	56.2	56.7	56.5	50.8
9. Average kWh in 0800-0900	32.2	33.4	34.7	24.9	30.0	42.2	47.3	45.6	47.6	39.9
10. Average kWh in 0900-1000	35.1	34.0	36.8	28.8	33.9	44.5	48.4	48.4	47.9	42.3
11. Average kWh in 1000-1100	39.1	39.0	36.7	32.5	35.8	44.9	49.6	47.1	47.8	41.6
12. Average kWh in 1100-1200	39.5	42.0	43.3	33.3	35.7	45.5	48.9	46.4	45.3	40.8
13. Average kWh in 1200-1300	43.3	43.7	43.2	38.1	40.8	47.4	50.5	48.0	47.5	41.7
14. Average kWh in 1300-1400	45.1	46.4	45.1	42.0	42.6	47.0	51.0	49.8	51.0	44.5
15. Average kWh in 1400-1500	46.8	46.2	46.1	41.2	41.2	46.0	48.6	50.1	47.1	42.3
16. Average kWh in 1500-1600	45.1	48.1	45.2	43.4	40.4	44.8	47.0	48.0	45.4	41.0
17. Average kWh in 1600-1700	46.9	50.5	47.4	46.7	40.8	42.2	47.8	46.9	44.2	39.7
18. Average kWh in 1700-1800	51.0	52.9	48.5	49.7	44.8	49.0	54.7	51.9	50.6	48.0
19. Average kWh in 1800-1900	54.3	53.8	52.1	53.2	48.8	53.5	56.7	55.5	56.1	52.5
20. Average kWh in 1900-2000	55.8	54.2	54.2	51.0	50.4	55.1	57.2	57.5	58.5	53.6
21. Average kWh in 2000-2100	53.9	54.0	53.2	50.4	51.4	57.7	58.0	57.9	58.5	52.7
22. Average kWh in 2100-2200	53.6	54.2	52.6	52.9	56.1	58.0	60.4	59.3	59.8	55.9
23. Average kWh in 2200-2300	56.3	57.3	54.5	53.1	54.2	59.1	61.1	60.4	60.4	54.1
24. Average kWh in 2300-2400	52.4	56.2	51.7	50.0	50.9	59.2	60.9	59.3	57.8	51.1
25. Average daily kWh	46.6	48.1	46.4	43.4	44.1	51.8	55.0	54.4	54.4	49.0
26. Average 60-min noncoincident max demand	42.3	44.2	42.7	37.7	39.9	44.7	42.9	45.6	44.7	40.3
27. Average 15-min noncoincident max demand	32.5	35.2	35.7	34.1	38.7	42.6	39.2	40.1	40.2	39.3

[a]Percentage differences are calculated relative to the non-SSI population. All differences are statistically significant at the .01 level.



Key: ——— Non-SSI
------ SSI
# Denotes statistically significant differences in the estimated hourly loads at the 10 percent level of significance

Figure 4-1. Comparison of estimated hourly usage of SSI and non-SSI customers — July weekdays.



Key: ——— Non-SSI
------ SSI
# Denotes statistically significant differences in the estimated hourly loads at the 10 percent level of significance

Figure 4-2. Comparison of estimated hourly usage of SSI and non-SSI customers — January weekdays.

population. It should be emphasized that MCLF's are not estimated with high precision since they depend on the estimated average usage at a single hour.

Table 4-8 shows the results for each month during the study period for the MCLF based on usage at the hour of system peak (see Table 3-1). Statistical significance (at the .05 level) between the non-SSI and SSI MCLFs was detected only for the months of October, November, and January.

Table 4-9 shows the results for the second type of MCLF.

4.3.4 Weekdays/Weekend Days

Electricity consumption patterns for the non-SSI and SSI were derived separately for weekdays and weekend days within each calendar month. In each case, SSI-rate customers used less electricity than the non-SSI-rate customers. The patterns of differences were very similar to those described in Subsections 4.3.1 and 4.3.2, i.e., consumption was substantially less for the SSI population during each hour of the 24-hour day and the largest percentage differences in usage occurred during the winter months. Percentage differences appeared to be slightly larger for the weekend days than for the weekdays. Population estimates and results of statistical tests for these time periods are summarized in Table 4-10.

4.4 COMPARATIVE ANALYSIS RESULTS FOR SPECIFIC RATE CLASSES

Sample customers for the SSI rate study were selected from among North Carolina residential accounts in the Duke service area as of August 1979. These accounts were separated into the two primary populations of interest (SSI-rate and non-SSI-rate customers) as well as the three basic residential rates (R, RA, and RW). The number of accounts in the six categories are shown in Table 4-11, along with the percentage distributions.

TABLE 4-8. COMPARISON OF MONTHLY CLASS LOAD FACTORS, BASED ON USAGE AT HOUR OF SYSTEM PEAK, FOR NON-SSI AND SSI CUSTOMERS

Month	Population	Estimated average hourly kWh during month	Estimated average hourly kWh at hour of system peak	Estimated monthly class load factor (MCLF)	Estimated standard error of MCLF
1980:					
June	Non-SSI	1.250	1.845	.678	.056
	SSI	0.668	0.928	.720	.062
July	Non-SSI	1.547	2.038	.759	.048
	SSI	0.793	1.014	.782	.049
August	Non-SSI	1.541	2.438	.632	.032
	SSI	0.824	1.447	.569	.042
September	Non-SSI	1.266	1.572	.805	.053
	SSI	0.728	0.986	.738	.082
October	Non-SSI	1.321	2.174	.608	.037
	SSI	0.733	0.969	.756[a]	.043
November	Non-SSI	1.706	3.159	.540	.034
	SSI	0.823	1.221	.674[b]	.050
December	Non-SSI	2.000	2.968	.674	.034
	SSI	0.900	1.208	.745	.058
1981:					
January	Non-SSI	2.081	3.460	.601	.025
	SSI	0.949	1.320	.719[b]	.044
February	Non-SSI	1.851	3.175	.583	.029
	SSI	0.841	1.271	.662	.051
March	Non-SSI	1.594	2.401	.664	.029
	SSI	0.813	1.042	.780	.057

[a]Significantly different from the non-SSI MCLF at the .01 level.

[b]Significantly different from the non-SSI MCLF at the .05 level.

TABLE 4-9.
COMPARISON OF MONTHLY CLASS LOAD FACTORS,
BASED ON CLASS PEAK USAGE
FOR NON-SSI AND SSI CUSTOMERS

	Estimated class peak during month (kWh)		Estimated class load factor	
Month	Non-SSI	SSI	Non-SSI	SSI
1980:				
June	2.779	1.126	.45	.59
July	2.884	1.351	.54	.59
August	2.776	1.442	.55	.57
September	2.387	1.346	.53	.53
October	2.341	1.554	.57	.48
November	3.382	1.707	.50	.48
December	3.642	1.548	.55	.58
1981:				
January	3.460	1.486	.60	.64
February	3.175	1.271	.57	.60
March	2.524	1.269	.61	.62

TABLE 4-10. ESTIMATED AVERAGE DAILY ELECTRICITY USAGE FOR NON-SSI AND SSI CUSTOMERS, BY MONTH AND TIME OF WEEK

	Estimated average kWh (per customer, per day)[a]						Percentage differences[b]		
	Weekdays		Weekend days		All days				
Month	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Weekdays	Weekend	All days
1980:									
June	28.2	15.7	34.2	16.9	30.0	16.0	44	51	47
July	36.3	19.2	38.9	19.3	37.1	19.2	47	51	48
August	37.1	20.1	36.6	19.3	37.0	19.8	46	47	46
September	29.9	17.2	32.0	17.4	30.5	17.3	42	46	43
October	31.4	17.8	33.1	17.8	31.8	17.8	43	46	44
November	40.3	19.8	41.9	19.7	41.0	19.7	51	53	52
December	46.1	21.0	52.1	22.8	48.0	21.6	54	56	55
1981:									
January	48.1	22.5	53.7	23.3	49.9	22.8	53	57	54
February	44.2	20.3	44.9	20.2	44.4	20.2	54	55	54
March	37.9	19.4	39.1	19.8	38.3	19.5	49	50	49

[a]All differences between the non-SSI and SSI customers are statistically significant at the .05 level.

[b]Percentage differences are calculated as 1 - Y/X times 100 percent, where X and Y denote, respectively, the estimates for the non-SSI and the SSI populations.

TABLE 4-11. CATEGORIES OF ACCOUNTS

Rate class	Sample-eligible customers not on SSI rate		Sample-eligible customers on SSI rate	
	No.	%	No.	%
R	147,408	20.9	2,713	34.2
RA	198,684	28.2	421	5.3
RW	357,632	50.8	4,804	60.5
Total	703,724	100.0	7,938	100.0

The disparity between the two distributions shown in Table 4-11 is sufficient to have explained many of the differences described in the previous section. For example, suppose a particular parameter had values of 1, 5, and 2 for the R, RA, and RW rate classes, respectively, and suppose that these values held for both the SSI and non-SSI customers. Then the overall parameter values (i.e., combining over rate classes as in Section 4.4) for the SSI and non-SSI customers would be the following:

$$\text{Non-SSI:}\quad .209(1) + .282(5) + .508(2) = 2.635$$
$$\text{SSI:}\quad .342(1) + .053(5) + .605(2) = 1.817.$$

There is a 31-percent difference in these overall parameter values, even though there was no difference in the values assumed for the three specific rate classes. This simple example indicates that it is important to consider the separate rate classes, and to understand to what extent the distributional differences of the two populations over rate classes account for the differences described and presented in Section 4.4. This is the purpose of this section. Detailed results will be presented in a companion volume to this report.

Table 4-12 presents estimates, by rate class, of the average usage of non-SSI and SSI customers on the day of monthly system peak. The results of

TABLE 4-12. COMPARISON OF AVERAGE ELECTRICITY CONSUMPTION OF NON-SSI AND SSI CUSTOMERS ON DAYS OF MONTHLY SYSTEM PEAKS, BY MONTH AND RATE CLASS

Rate class	Estimate	1980 Jun. 3	Jul. 16	Aug. 6	Sept. 3	Oct. 30	Nov. 20	Dec. 4	1981 Jan. 12	Feb. 4	Mar. 19
R	Non-SSI kWh:	18.6	22.4	27.6	18.9	23.3	25.0	22.0	25.7	22.0	18.4
	SSI kWh:	12.9	15.0	17.3	15.8	12.7	13.8	16.9	21.3	18.2	16.7
	Difference:[a]	5.7	7.4	10.4	3.0	10.6	11.2	(5.2)	(4.5)	(3.8)	(1.7)
	% Difference:	30.6	33.1	37.5	16.0	45.7	44.7	23.4	17.4	17.4	9.1
RA	Non-SSI kWh:	51.8	64.4	59.8	48.5	56.3	88.9	85.7	134.7	119.0	80.6
	SSI kWh:	26.4	31.9	30.7	25.4	59.3	70.7	60.3	104.7	93.9	64.9
	Difference:[a]	25.3	32.5	29.2	23.1	(-3.0)	(18.2)	25.4	30.0[b]	25.1[b]	15.7[b]
	% Difference:	48.9	50.4	48.7	47.6	5.4	20.5	29.7	22.3	21.1	19.4
RW	Non-SSI kWh:	28.2	39.3	41.3	31.7	30.7	38.4	37.3	38.2	35.4	31.1
	SSI kWh:	19.3	24.5	25.4	19.7	20.4	22.6	20.3	21.9	21.5	21.5
	Difference:[a]	8.9	14.8	15.9	12.0	10.4	15.7	17.0	16.2	13.9	9.6
	% Difference:	31.6	37.6	38.5	37.9	33.8	40.9	45.5	42.5	39.3	31.0
All	Non-SSI kWh:	32.9	42.8	43.7	33.8	36.4	49.9	47.8	62.8	56.2	42.4
	SSI kwh:	17.5	21.7	22.9	18.7	19.8	22.2	21.3	26.1	24.2	22.1
	Difference:[a]	15.4	21.2	20.8	15.1	16.6	27.6	26.5	36.7	32.0	20.3
	% Difference:	46.8	49.4	47.5	44.7	45.6	55.5	55.5	58.5	57.0	47.8

[a]Difference between the non-SSI and SSI customers are statistically significant at the .05 level unless otherwise designated. Differences which are not significant at the .01 level are shown in parentheses.

[b]Differences between the non-SSI and SSI customers are statistically significant at the .10 level.

this table clearly indicate that the distributional difference described above is responsible for part of the difference between the two populations, since the overall difference is generally larger (on a percentage basis) than the differences for the individual rate classes. For the day of annual system peak (January 12, 1981), for instance, the differences for the R and RA classes are 17.4 percent and 22.3 percent, respectively (the former is not statistically significant, and the latter is significant at the .05 level), as compared to the overall difference of 58.5 percent. Thus, although there generally appear to be differences between the two populations even when evaluated on a rate-specific basis, these differences tend to be smaller in magnitude than the overall differences and are frequently not statistically significant.

5.0 ANALYSIS OF CUSTOMER SURVEY DATA

This chapter presents an analysis of the customer survey data described in Section 3.2. The appliance, profile, and household characteristics of the participating customers are the key elements in these data. The objectives of this analysis are to determine:

1. How the SSI and non-SSI populations differ in terms of their respective appliance saturations and household characteristics, and

2. How the sample characteristics of the SSI and non-SSI customers differ from the likely population characteristics of these groups of customers.

The comparative analysis of usage data presented in Chapter 4 showed large differences between the loads of the typical SSI and typical non-SSI customer. Objective one will determine if the load differences result from the two groups of customers having significantly different appliance saturations and household characteristics. In order to use the survey data to achieve objective one, it is necessary to compute weighted means and variances of the survey variables to estimate the population characteristics. The weights are defined in such a way that each weighted mean would, to the extent possible, estimate its corresponding population mean. This chapter also provides details of the weighted means computations and potential sources of inaccuracy caused by sample design peculiarities.

The second objective is important for evaluating the reliability of the covariate regression results that are presented in Chapter 6. Regression estimates are most precise when computed at the sample means of the explanatory variables. In Chapter 6, however, regression estimates are computed at the estimated population means computed in this chapter. If any of these population means differ substantially from their corresponding sample means, then a considerable loss of precision in the load estimates will result. In addition, the potential for estimation bias resulting from model misspecification is increased when estimates are computed at noncentral values of the explanatory variables.

5.1 Description of the Analysis Variables

The survey variables that will be used here to characterize the SSI and non-SSI populations are defined in Table 5-1. Apart from the three quantitative household characteristics variables at the bottom of the table, the remaining variables in Table 5-1 are indicator variables. The first 14 are appliance indicators, the next 3 are indicators for type of dwelling, and the final 3 are indicators for secondary heat sources.

5.2 Data Compilation and Reduction

The survey data consist of the responses from 199 SSI and 154 non-SSI customers. This is the entire set of customers who participated in the survey and includes customers who dropped out of the study, their replacements, and also those with incomplete hourly usage records.* The total of 353 customers is roughly 50 percent larger than the totals available for the monthly analyses of the load data. The reason for using the responses of all 353 customers, rather than just those eligible for the load analysis, is simply that the larger data set will yield more precise population estimates (i.e., weighted means) of the survey variables.

*Many customers' usage records were missing due to meter failure.

TABLE 5-1. DEFINITIONS OF APPLIANCE AND DEMOGRAPHIC SURVEY VARIABLES

Variable Name	Definition
Appliances	
Cooling	
CAC	Indicator for central air conditioner
WAC	Indicator for one or more window air conditioners
Heating	
HEAT PUMP	Indicator for heat pump
EL._FURN	Indicator for electric furnace
RM_BY_RM	Indicator for electric room by room heat
Discretionary	
HOTW	Indicator for electric water heater
RANGE	Indicator for electric range
WASH	Indicator for electric clothes washer
DRY	Indicator for electric clothes dryer
DISH	Indicator for electric dishwasher
Nondiscretionary	
FF_FREZ	Indicator for frost-free freezer
NFF_FREZ	Indicator for non-frost-free freezer
FF_REF	Indicator for frost-free refrigerator
NFF_REF	Indicator for non-frost-free refrigerator
Household Characteristics	
Type of Dwelling	
HOUSE	Indicator for house
MOBILE	Indicator for mobile home
APT	Indicator for apartment
Secondary Heat Source	
FPL	Indicator for fireplace
WST	Indicator for woodstove
SPC	Indicator for portable space heater
Other Household Characteristics	
SIZE_RES	(Size of residence in square feet)/1000
VAL_RES	(Value of residence in dollars)/1000
NOHHMEM	Number of household members

5.2.1 Collapsing the Original Strata

The computation of variances using data from stratified samples requires that there be at least two sample members from each stratum. The sampling design prepared by Duke Power Company and utilized in this study called for the selection of only one customer from each stratum, but there were several strata in the SSI population that failed to contain a single household. Before weighted sample means and variances could be computed, the original 192 strata constituting each of the customer classes had to be collapsed into a smaller set of superstrata ("cells") each of which contained at least two customers. See Chapter 2 for details of the sample design.

While any number of collapsing schemes might have been chosen, the scheme used here combined the four off-season strata into a single stratum, leaving only 48 strata per customer class as shown in Table 5-2. If none of the originally defined strata were empty, there would have been at least four households in each cell.* Some of the original strata, however, contained none of the sample households and some sample households were also missing survey information, which caused some cells to have less than four households. In addition, there were still less than the minimum number of two households for a few cells, which required some additional collapsing (also shown in Table 5-2).

The additional collapsing was performed by joining that cell adjacent to the zero- or one-member cell that caused the selection probability in the newly formed cell to be as near as possible to the selection probability

*Since replacement were included in the dataset, there could be more than four households supplying data in some cases.

TABLE 5-2. POPULATION AND SAMPLE CELL COUNTS OF SUMMER AND WINTER STRATIFICATION

	SSI Rate = R Summer					non-SSI Rate = R Summer			
Winter	1	2	3	4	Winter	1	2	3	4
1	820	319	32	2	1	48,878	1,823	72	13
	7	7	4	0		3	4	3	2
2	127	451	46	9	2	24,779	27,268	137	19
	4	4	7	5		3	4	3	3
3	28	248	120	14	3	2,068	35,610	1,827	42
	4	7	5	4		3	4	3	2
4	18	111	240	78	4	283	1,642	2,529	418
	4	4	4	6		4	0	4	4

	Rate = RA Summer					Rate = RA Summer			
Winter	1	2	3	4	Winter	1	2	3	4
1	143	0	0	0	1	35,601	18,913	1,821	180
	11	0	0	0		3	4	2	2
2	146	7	0	0	2	9,171	41,945	19,577	782
	13	4	0	0		4	4	4	4
3	89	15	1	0	3	1,222	13,956	34,833	9,501
	10	5	1	0		4	3	3	4
4	14	5	1	0	4	117	550	3,603	6,912
	5	3	0	0		2	4	2	3

	Rate = RW Summer					Rate = RW Summer			
Winter	1	2	3	4	Winter	1	2	3	4
1	1,438	269	25	1	1	99,954	6,772	494	18
	6	5	5	0		4	3	4	1
2	52	1,083	143	15	2	42,239	87,135	1,091	38
	4	6	4	4		3	3	3	4
3	44	497	422	82	3	3,602	72,606	25,273	158
	7	5	4	5		3	4	3	3
4	16	40	123	78	4	584	2,916	13,259	1,493
	3	4	3	6		4	4	4	2

Note: Collapsed cells indicated by boxes.

Stratum boundaries are illustrated in Tables 2-2 through 2-7.

that existed in the zero- or one-member cell prior to collapsing. Stated formally, let C_o be a cell with n_o sample members and N_o population members where n_o = 0 or 1. Also, let C^j, $j = 1,\ldots,k$ ($k \leq 4$) be k adjacent cells having sample and population sizes of n_j and N_j, respectively. For j = 1,...k, compute Δj, the jth difference in the selection probabilities, where

$$\Delta_j = \left| \frac{n_o}{N_o} - \frac{n_o + n_j}{N_o + N_j} \right| \tag{5-1}$$

Then combine cell C_o with that cell C_j for which the value of Δ_j is the smallest. Application of the collapsing scheme described above led to a partitioning of the 353 survey households into the 44 SSI plus 46 non-SSI cells shown in Table 5-2.

A word of caution is necessary as a result of the collapsing that had to be performed prior to the computation of the weighted means and variances. There is no guarantee that collapsing any two strata is valid since combining strata is equivalent to assuming no differences in the compositions of customers within each of the strata being combined. Should substantial differences exist in the distribution of, say, a particular appliance within two strata being combined, and if the selection probabilities differed for these two strata, then there will be some bias introduced into the computation of the estimated population saturation of that appliance.

Several collapsing schemes were tested before it was decided to collapse over the off-season strata to minimize the probability of serious biases occurring. For example, collapsing over the summer strata was rejected due to an uneven distribution of air-conditioners among these strata. Similarly, winter collapsing was rejected due to differing saturations of electric heating among these strata.

5.2.2 Computation of Weighted Means and Variances

Given the collapsed strata (cells) indicated in Table 5-2, weighted means and variances are computed as follows. Let n_j and N_j be the sample and population size of the jth cell and let N equal ΣN_j. Let y_{ij}, i = $1,\ldots,n_j$ be the n_j sample values for this cell for an arbitrary survey variable Y. Then the jth cell mean of Y is $\bar{y}_j = n_j^{-1} \sum_i y_{ij}$ and the weighted estimate of the population mean of Y is

$$\bar{y}_w = N^{-1} \sum_j N_j \bar{y}_j \tag{5-2}$$

Similarly, the weighted estimate of the population variance of Y is

$$s_w^2 = N^{-2} \sum_j \frac{S_j^2}{n_j} (N_j - n_j)N_j \tag{5-3}$$

where

s_j^2 is the sample variance of Y for the jth stratum,

5.2.3 Results

The estimated population means and their standard errors computed according to Equations (5-2) and (5-3) for the survey variables defined in Table 5-1 are shown in Table 5-3. The unweighted sample means of these variables also are shown in Table 5-3.

Objective one is concerned with how the SSI and non-SSI populations differ with regard to their appliance saturations and the other household characteristics covered in the survey. Table 5-3 shows that for a large number of the survey variables, the weighted means differ significantly between the two populations. In all cases the differences point toward higher average per household usage in the non-SSI class than in the SSI class.

Among the electric appliances, the non-SSI class has a significantly higher saturation of central air conditioners, heat pumps, room by room

TABLE 5-3. ESTIMATED POPULATION MEANS AND UNWEIGHTED SAMPLE MEANS OF 23 SURVEY VARIABLES

	Unweighted Sample Means			Estimated Population Means		
	Non-SSI	SSI	Difference[a]	Non-SSI	SSI	Difference[a]
Central Air	.384	.093	.291**	.237	.029	.208**
Window Air	.340	.275	.065	.307	.172	.135
Heat Pump	.109	.025	.084	.062	.007	.055**
Electric Furnace	.077	.064	.013	.073	.011	.062
Room by Room Heat	.192	.181	.011	.147	.035	.112**
Water Heater	.788	.730	.058	.853	.709	.144**
Range	.871	.833	.038	.832	.805	.026
Washer	.789	.554	.235**	.680	.473	.207*
Dryer	.635	.216	.419**	.449	.145	.304**
Dishwasher	.455	.049	.406**	.265	.006	.259**
Freezer, frost-free	.192	.083	.109**	.116	.073	.043
Non-frost-free	.288	.328	-.040	.379	.355	.024
Refrig. frost-free	.763	.441	.322**	.732	.345	.387**
Non-frost-free	.231	.539	-.308**	.251	.634	-.383**
House	.815	.672	.143**	.844	.758	.086
Mobile Home	.134	.127	.007	.100	.065	.035
Apartment	.051	.186	-.135**	.055	.150	-.095
Fireplace	.211	.093	.118**	.137	.116	.021
Woodstove	.179	.181	-.002	.148	.235	-.087
Space Heater	.032	.059	-.027	.006	.112	-.106*
Square Feet of Residence	1.484	.899	.585**	1.317	.894	.423**
Value of Residence	44.347	17.717	26.630**	35.686	14.045	21.641**
Number of Household Members	2.968	2.005	.963**	2.849	1.676	1.173**

[a]A single asterisk (*) indicates the difference in weighted means is statistically significant at the 10 percent level, a double asterisk (**) at the 5 percent level.

heating systems, water heaters, washers, dryers, dishwashers, and frost-free refrigerators. Members of the non-SSI customer class have homes that average 423 more square feet and $21,000 more value than their SSI counterparts. The typical non-SSI household has approximately one more family member than the typical SSI household.

The important issue is how these significant differences might contribute to the differences in the loads of these two groups of customers. In the summer months, a large differential in average air conditioning usage per household is certain to exist, since about 54 percent of all non-SSI households have some form of air conditioning compared to about 20 percent of SSI households. A similar situation exists for electric heat usage in the winter months with the total saturations of the various primary electric heat systems equal to about 30 percent among the non-SSI households, but only about 5 percent among the SSI households.

Water heater usage is most likely a major year-round source of differing usage between the two customer classes. Not only is the electric water heater saturation about 15 percent higher among non-SSI customers, but the major appliances that draw hot water--namely, clothes washers and dishwashers--have saturations in the non-SSI population of 21 percent and 26 percent, respectively, in excess of those in the SSI population. If these major appliances are utilized at similar rates by both customer classes, then the average per household water heater usage will be much higher in the non-SSI class. One other major appliance, the electric clothes dryer, is also much more prevalent among non-SSI households (45 percent ownership) than among SSI households (15 percent ownership).

The survey data show these many sources that contribute to greater non-SSI than SSI usage. It is not surprising that the comparative analysis presented in Chapter 4 estimates that indicated SSI households typically had loads about 50 percent less than those of non-SSI households. The survey results reinforce the importance of presenting both a comparative and a covariate analysis in this study.

The second objective of determining if large differences exist between any pairs of sample and weighted means can be achieved by analyzing the results of Table 5-3. There is a danger that the contribution to the load as estimated by a regression analysis will be unreliable for variables that have large differences between sample and weighted means. Errors in prediction due to errors in specification and estimation will be magnified when the weighted means deviate substantially from the sample means.

There are some variables for which fairly large deviations exist between the sample and weighted means because high users and some rate classes were oversampled. For the non-SSI population, the sample saturations are more than 10 percent greater than the estimated population saturations for the central air conditioners, washer, dryer, and dishwasher. For the SSI population, differences this large occurred for the air conditioning, electric heat, and refrigerator variables. On net, these discrepancies widen the confidence limits for the regression load estimates relative to what they would have been if the estimates were computed at the sample means.

An effort was made to compute the weighted means and variances with as little bias as possible; however, some bias may be present in the estimates. This is because the stratified sampling design prepared by Duke Power Company called for the selection of only one customer per stratum, which is insufficient for the computation of variances. Strata had to be combined to complete variances; therefore bias is possible in the weighted means.

The analysis of customer survey data has shown that the population of non-SSI households has a significantly higher proportion of many major electric appliances than does the SSI population. The non-SSI customers also tend to have larger, more expensive residences and larger family sizes.

The sample means of several of the survey variables were substantially larger than the corresponding estimates of their population means due to the oversampling of larger users in each of the populations being sampled. The effect of the differing sample and population means is to increase the variance of the load estimates presented in the covariance analysis of Chapter 6.

6.0 COVARIANCE ANALYSIS

In this chapter the information obtained from the customer survey is utilized to develop a behavioral model of hourly electricity demand for SSI and non-SSI households. The survey data consist of information on the appliance holdings, secondary heat sources, household size and value, and family size of each participating household. Together, these variables are referred to as "covariates" because they correlate with electricity usage. The model developed for this analysis is a linear regression model of hourly usage and a collection of independent variables constructed from the customer survey data presented in Chapter 5.

The objectives of the covariance analysis are:

1. To determine whether the usage of SSI customers is different from non-SSI customers when influences of covariate variables are included;

2. To determine whether SSI customers differ from other "low use" customers.

These objectives will be achieved by using the regression models to carry out three important activities. These activities are:

1. Compare the estimated hourly per household loads of the SSI and non-SSI customer classes;

2. Estimate average hourly usage per household of a hypothetical non-SSI class having appliance and demographic compositions identical to those of the SSI population and compare the hypothetical non-SSI load with that estimated for the SSI customer class; and,

3. Perform the above-mentioned estimations and comparisons separately for the three rate classes (R, RA, and RW).

The first set of comparisons listed above has already been made in the comparative analysis of Chapter 4. The covariance results of these comparisons/estimations tend to verify the comparative analysis results. An added benefit from performing these estimations is that the precision of the estimates may be improved over that achieved in the comparative analysis.

The second and third activities are necessary to separate differences in the typical load patterns of SSI and non-SSI households into those portions attributable to appliance and demographic differences and those attributable to differing appliance utilization habits. If the SSI households can be shown to use electricity in a different manner from non-SSI households, <u>controlling for differences in appliance saturations and demographic characteristics</u>, then the case for placing them on a separate rate schedule is strengthened. On the other hand, if it is found that the large differences in the load patterns of typical SSI and non-SSI households can be attributed almost entirely to differences in the covariates, then it can be assumed that SSI and non-SSI households behave alike, and the case for placing them on a separate rate is weakened.

6.1 DATA COMPILATION AND REDUCTION

The covariance results are presented for four different "day types": nonholiday weekdays, holidays and weekend days, the summer and winter system peak days, and days in the peak summer and winter months containing an hour for which system usage was at least 90 percent of the seasonal peak. Weekends and holidays are treated separately from weekdays because the patterns of hourly loads for these two day types differ and it is important to develop load curves that realistically characterize particular days. The system peak days of each month are of interest since the utility's cost of service is greatest on these days. Analyzing a single day of usage, however, will produce load estimates having high variances. "Near peak" days, such as those days for which the system peak was greater than 90 percent of the seasonal system peak, are a compromise solution that provides more precise estimates. In July and January, nine and seven days, respectively, fell into this "90 percent of peak" category.

The number of customers that could be used in the monthly regression analyses varied from month to month. In June (the first month of the experiment for which some data are available), several of the customers had not had meters installed causing the analysis sample to be somewhat smaller than that of the other months. Customers periodically dropped out of the study and were subsequently replaced by Duke Power Company. Since relatively complete data throughout a full month was necessary for inclusion of a customer in the analysis, the number of customers eligible for each month's analysis varied. Occasional meter failures that caused a customer's usage values to be invalid or missing for a period of time created additional fluctuations in the number of customers. A summary of customer deletions and inclusions for the comparative analysis was provided earlier in Table 4-3. Table 6-1 provides data on additional deletions due to missing appliance and demographic data and final count of customers available for the monthly covariance analyses.

6.2 MODEL SPECIFICATION

This section describes the process of specifying the covariate regression model. The study considered only linear models, but numerous possible specifications remained. The model of electricity demand required:

TABLE 6-1. DEMOGRAPHIC EDITS AND FINAL SAMPLE SIZES BY MONTH FOR COVARIANCE ANALYSIS

Month	Appliance and Demographic Edits[a]		Final Sample Size	
	Non-SSI	SSI	Non-SSI	SSI
June 1980	16	18	97	127
July	18	19	105	122
August	15	17	111	124
September	18	19	113	125
October	28	17	110	126
November	35	16	115	137
December	37	20	115	145
January 1981	31	20	118	147
February	32	18	114	145
March	32	19	119	141

[a]Values shown are the number of customers excluded from the covariance analyses of a given month due to lack of data on one or more of the covariates.

1. Specification of the dependent variable--find a transformation of kWh such that the variance of the transformed variable is approximately constant over its range.

2. Specification of independent variables--using the information provided in the survey data, construct a concise set of independent regression variables that correlate significantly with the transformed usage variables in at least some hours.

3. Specifications of differences in SSI and non-SSI customers--determine the manner and extent to which the regression relationships will be allowed to differ between SSI and non-SSI households.

6.2.1 Specification of Dependent Variable

A plot of usage against its predicted values from preliminary regression results indicated that the variance of the residuals increased over the range of the predicted variables. This type of heteroskedasticity is typical of variables with a finite lower bound (in this case, zero) and has been noted in most econometric analyses of electricity consumption data. The standard procedure used to reduce the heteroskedasticity is to adopt the natural logarithmic transformation (ln). The ln(kWh+1) transformation was used to avoid difficulties for usage values of zero. A subsequent preliminary analysis of the ln(kWh+1) values confirmed that there was no longer significant heteroskedasticity.

6.2.2 Formation of the Independent Variables

The 23 covariates available from the survey data consist of 14 electric appliance variables and 9 nonappliance variables. The electricity used by a household is the sum of the electricity used by the various appliances within the household, therefore each independent variable was defined with the intention that it would correlate with the usage of a specific type of appliance. Often, one or more nonappliance variables were incorporated into the definitions of an appliance-usage variable when this would increase its correlation with the end-use of that appliance. Table 6-2 summarizes the appliance-usage variables that were formed from the survey data.

The rationale for the variable constructions shown in Table 6-2 is as follows: AC (air conditioning) usage should be roughly proportional to the size of the cooled area; therefore the dummy variable for central air conditioning is multiplied by the square feet of the residence. Window air conditioners are assumed to cool about one-fifth of the residence. The logarithmic (log) transformation of the cooling variable is used to correspond to the log transformation of usage.

Hot water use is assumed to increase linearly with the number of household members. Again, the log of the positive values of this variable was taken to correspond to the log transformation of the dependent variable. The clothes-washing and clothes-drying variables are defined also as the product of indicator variables and the log of the number of household members.

The electric heat variable was defined as the product of the efficiency of the type of heat used and the square feet of the residence. The relative efficiencies of the heat pump, room-by-room system, and electric furnace were taken from Taylor (1979, p. E.11).

The refrigerator-freezer variable was constructed by weighting the indicator variables of frost-free and non-frost-free refrigerators and freezers by the estimated kW demand of each unit. The kW estimates were taken from Miedema et al. (1980, p. 79).

6.2.3 Modeling Differences in SSI and Non-SSI Appliance Utilization

There are basically three options in allowing the utilization rates of the appliance (i.e., the regression coefficients) to differ between SSI and

TABLE 6-2. DEFINITION OF COMPOSITE VARIABLES USED IN COVARIATE REGRESSION ANALYSIS

Variable	Definition[a]
L_AC	LOG [(1/1000) * SIZE_RES]*(CAC + 0.2*WAC)
HOTW_USE	HOTW * LOG (NOHHMEM + 1)
EF	.4167*HEATPUMP + .7708*RM_BY_RM + .9167*EL_FURN
L_HEAT	(1/1000) * (EF * LOG (SIZE_RES))
L_REFRZ	LOG (0.7*NFF_REF + 1.8*FF_REF + 1.32*NFF_FREZ + 2.0*FF_FREZ)
WASHING	WASH*HOTW*LOG(NOHHMEM + 1)
DRY_USE	DRY*LOG(NOHHMEM + 1)

[a]The survey variables appearing in these definitionns are defined in Table 5-1.

non-SSI households. The first option is to pool the SSI and non-SSI customers into a single regression and then allow separate regression coefficients for each group by including interactions of all of the independent variables with an SSI indicator variable. The second option is to include only that subset of interaction variables that are deemed important. The third option is to run separate regressions for the SSI and non-SSI groups. The first and third options yield identical estimates of the appliance coefficients of each group, but different estimates of the standard errors of these coefficients. Choosing between these two options is a matter of assessing the validity of pooling the two samples. The third option should be chosen when pooling is inappropriate. If pooling is appropriate, then one of the first two options should be chosen.

The test for the appropriateness of pooling compares the variance of the regression residuals from the SSI and non-SSI regressions (option 3). If, through an F-test, the hypothesis that the variances are equal can be rejected, then the data should not be pooled.

Table 6-3 shows F-tests that were performed from the results of selected hourly summer and winter peak day regressions. In several hours, the SSI and non-SSI variances differed at the 5-percent level of significance. These results indicated that pooling was inappropriate and separate regressions were run for the SSI and non-SSI samples. While the possibility exists that the F-tests might not be rejected when applied to the average weekday regressions, a common model was adopted for all the day types considered. The extended decision was not to pool to the entire set of regressions.

TABLE 6-3. TESTS FOR EQUAL VARIANCES BETWEEN SSI AND NON-SSI REGRESSIONS[a,b]

Hour	F(Summer)[c]	F(Winter)[c]
8	1.826**	1.408**
10	1.533**	1.208
12	1.533**	1.332*
14	1.630**	1.617**
18	1.116	1.131
20	1.111	1.512**

[a]F-statistics were computed for peak day regressions of each season.

[b]Statistical significance at the 10 percent level is denoted by a single asterisk (*); at the 5 percent level, by a double asterisk (**).

[c]These F-statistics were computed as:

$$F_{df_1,df_2} = \frac{\text{Residual Variance from Non-SSI Regression}}{\text{Residual Variance from SSI Regression}}$$

where in the summer $(df_1,\ df_2) = (111,140)$

and in the winter $(df_1,\ df_2) = (99,116)$

6.2.4 Final Model Specification

The decisions made thus far have been: to run separate linear regressions for the SSI and non-SSI groups, to use ln(kWh+1) as the dependent variables, and to use independent variables--some subset of the survey variables listed in Table 5-1 and the composite variables defined in Table 6-2. To arrive at a final model specification, the independent variables to include in this subset must be determined.

The method of selecting the final list of independent variables was to run preliminary hourly regressions using the summer and winter peak day data in which the following variables were included:

Summer: L_AC, HOTW_USE, L_REFRZ, RANGE, WASHING, DRYING, VAL_RES

Winter: L_HEAT, WST, HOTW_USE, L_REFRZ, RANGE, WASHING, DRYING, VAL_RES

The coefficients of these variables given by the estimated regressions were examined; whenever a particular variable was consistently nonsignificant at the 10-percent level, that variable was dropped from the specification. Consistent nonsignificance in both the summer and winter sets of regressions occurred only for the variable WASHING. Careful inspection of the coefficients, however, revealed a high negative correlation between the VAL_RES and L_AC coefficients. It was then discovered that the correlation between VAL_RES and L_AC variables was 0.711, which explained the negative correlation of the regression coefficients. Since air conditioning use was regarded as an important end-use to estimate, the VAL_RES variable was dropped to eliminate its effects on the L_AC estimates.

The final model adopted is shown in Equation 6-1.

$$\ln(kWh^{s}_{it} + 1) = a^{s}_{t} + \sum_{j=1}^{k} b^{s}_{jt} Z_{j} + e^{s}_{it} , \qquad (6\text{-}1)$$

where

kWh^{s}_{it} = kilowatthours consumed in hour t (t=1, 2,..., 24) by the ith household in the SSI sample (s=1) or non-SSI sample (s=2)

Z_j = jth independent variable

a^{s}_{t}, b^{s}_{jt} = regression coefficients, and

e^{s}_{it} = random error term.

For the summer regressions (June-October),

$$\{Z_j\} = \{\text{L\_AC, HOTW\_USE, L\_REFRZ, RANGE, DRY\_USE}\} \text{ and}$$

for the winter regressions (November-March),

$$\{Z_j\} = \{\text{L\_HEAT, WST, HOTW\_USE, L\_REFRZ, RANGE, DRY\_USE}\} .$$

The final number of independent variables included in the regressions (five in the summer; six in the winter) is small in comparison with the much larger number of survey variables available for the analysis. The reasons for using such a small number are:

1. The five major appliance types included usually account for at least 90 percent of a household's total electricity consumption. It is very difficult to obtain accurate estimates of the smaller appliance effects when the large appliances are this dominant.

2. Because significant correlations existed among many of the survey variables, only the essential variables were included to minimize the effects of multicollinearity on the estimated coefficients and thereby increase the precision of the estimated loads.

The sample correlations of the included independent variables are shown in Table 6-4. Note that many statistically significant correlations exist among these variables, but that none are greater than 0.430. While the presence of these correlations will tend to decrease the accuracy and precision of the estimates of the individual appliance effects, it should have

TABLE 6-4. CORRELATIONS AMONG INDEPENDENT REGRESSION VARIABLES[a,b]

	Summer (July peak day sample)				
	L_AC	HOTW_USE	L_REFRZ	RANGE	DRY_USE
L_AC	-	.029	.273**	.123	.389**
HOTW_USE	-.020	-	.096	.296**	.326**
L_REFRZ	.094	.231**	-	.108	.358**
RANGE	.079	.218**	.188**	-	.337**
DRY_USE	.124	.327**	.323**	.089	-

	Winter (January peak day sample)					
	L_HEAT	WST	HOTW_USE	L_REFRZ	RANGE	DRY_USE
L_HEAT	-	.271**	.430**	.257**	.299**	.314**
WST	-.111	-	.229**	.174	.094	.314**
HOTW_USE	.334**	-.016	-	.083	.299**	.177*
L_REFRZ	.231**	.176**	.226**	-	.190**	.290**
RANGE	.209**	-.061	.235**	.133	-	.297**
DRY_USE	.248**	.044	.410**	.281**	.104	-

[a]Correlations below each diagonal pertain to SSI sample; those above the diagonals pertain to non-SSI sample.

[b]Significance at 10 percent level is denoted by a single asterisk (*); at 5 percent level, by a double asterisk (**).

little effect on the estimate of total consumption and the precision with which total consumption is estimated.

6.3 RESULTS

The regression model of Eq. (6-1) was estimated for the SSI and non-SSI samples using consumption data from each month of the experiment. For all months, weekdays and weekend days are considered separately. Regressions were estimated also for the peak summer and winter months (July and January), peak day and "nearly peak day."

6.3.1 Appliance Effects

Tables 6-5 and 6-6 show the regression results for average July and January weekdays. These are illustrative of the results for all the regression analyses. Each table presents the hourly estimated regression coefficients, the number of customers supplying data for the regression, and the regression R-square. The results for SSI customers are shown in the top half of the tables; the non-SSI results in the bottom half. Coefficients significantly different from zero at the 10-percent level are indicated by a single asterisk (*) while those significant at the 5-percent level are identified by a double asterisk (**). Tables for the other regressions will be presented in a companion volume to this report.

The L_AC variable was statistically significant for all hours except from about 6 a.m. to 8 a.m. from June through September for both SSI and non-SSI households. The magnitude of the coefficients from the SSI regressions was much larger (about double) than that from the non-SSI regressions because of a much higher ratio of window to central air conditioners in the SSI sample and smaller residences for SSI customers. The larger coefficient on L_AC for this class simply means that the change in usage per unit change

TABLE 6-5 ESTIMATED HOURLY REGRESSION COEFFICIENTS, SAMPLE SIZE, AND REGRESSION R-SQUARE FOR JANUARY WEEKDAY ANALYSIS[a]

Non-SSI

HR	INTERCEP	L_HEAT	WST	HOTW_USE	L_REFRZ	RANGE	DRY_USE	N	R_SQUARE
1	0.4249**	0.9381**	-0.5638**	0.1764**	0.0365	-0.0303	0.1542**	118	.6038
2	0.3977*	0.9776**	-0.5342**	0.1819**	0.0302	-0.0476	0.1585**	118	.6162
3	0.3874*	1.0201**	-0.4945**	0.1711**	0.0098	-0.0376	0.1690**	118	.6212
4	0.3845*	1.0691**	-0.4785**	0.1638*	0.0304	-0.0684	0.1673**	118	.6266
5	0.3784*	1.0652**	-0.4823**	0.1804**	0.0459	-0.0806	0.1678**	118	.6190
6	0.3083	1.0323**	-0.4716**	0.2127**	0.1151	-0.0095	0.1591**	118	.6175
7	0.3587	0.9244**	-0.3207**	0.2981**	0.1503	-0.0623	0.1599*	118	.5718
8	0.4434*	0.9151**	-0.3535**	0.2599**	0.1634	-0.0080	0.1228	118	.5200
9	0.4773*	1.0479**	-0.4746**	0.2018**	0.1463	-0.0971	0.1384*	118	.5686
10	0.3416	0.9647**	-0.4756**	0.2029**	0.2307	-0.0606	0.1540*	118	.5874
11	0.2494	0.8376**	-0.4872**	0.2075**	0.2630*	-0.0062	0.1769**	118	.5728
12	0.2162	0.7412**	-0.4044**	0.2301**	0.2712*	-0.0317	0.2052**	118	.5726
13	0.2171	0.7154**	-0.4232**	0.2176**	0.2701*	-0.0127	0.1784**	118	.5652
14	0.1706	0.6436**	-0.4027**	0.2082**	0.2711*	0.0438	0.1715**	118	.5492
15	0.2374	0.6738**	-0.3690**	0.1712**	0.2087	0.0553	0.1671**	118	.5447
16	0.2665	0.6704**	-0.3863**	0.1622**	0.1868	0.0522	0.1854**	118	.6025
17	0.3616*	0.6332**	-0.3429**	0.1559**	0.1103	0.1348	0.1910**	118	.5748
18	0.4152**	0.5927**	-0.3316**	0.1884**	0.1109	0.1285	0.2163**	118	.6077
19	0.4737**	0.5767**	-0.3172**	0.2243**	0.0936	0.1148	0.2104**	118	.6028
20	0.5399**	0.5955**	-0.3020**	0.2538**	0.0677	0.0134	0.2053**	118	.5763
21	0.5469**	0.6751**	-0.3434**	0.2557**	0.0753	-0.0692	0.2325**	118	.5973
22	0.5261**	0.7313**	-0.2904**	0.2532**	0.1062	-0.1152	0.2141**	118	.5957
23	0.4994**	0.8041**	-0.3327**	0.2256**	0.1142	-0.1087	0.1847**	118	.5775
24	0.4503**	0.9016**	-0.4359**	0.1976**	0.0875	-0.0916	0.1782**	118	.6120

SSI

HR	INTERCEP	L_HEAT	WST	HOTW_USE	L_REFRZ	RANGE	DRY_USE	N	R_SQUARE
1	0.3987**	1.4734**	-0.1458	0.1841**	-0.0652	0.0363	-0.0087	147	.6125
2	0.4108**	1.5150**	-0.1371	0.1764**	-0.0831	0.0215	-0.0130	147	.6177
3	0.4159**	1.5470**	-0.1305	0.1773**	-0.0826	0.0007	-0.0071	147	.6326
4	0.3881**	1.6404**	-0.1315	0.1579*	-0.0660	0.0107	0.0285	147	.6735
5	0.3943**	1.6982**	-0.0872	0.1767**	-0.0715	0.0052	0.0028	147	.6754
6	0.4572**	1.6915**	-0.0520	0.2033**	-0.1145	0.0075	0.0381	147	.6774
7	0.4912**	1.6390**	-0.0757	0.2707**	-0.0859	-0.0325	0.0686	147	.6867
8	0.5743**	1.6605**	-0.0035	0.1975**	-0.1224	0.0814	0.0921	147	.6443
9	0.5862**	1.6133**	-0.0121	0.1375*	-0.1056	0.1483	0.0907	147	.6416
10	0.6273**	1.6021**	-0.0462	0.1194	-0.1365	0.1387	0.0690	147	.6398
11	0.5997**	1.4721**	-0.0734	0.1496*	-0.1229	0.1479	0.0685	147	.6228
12	0.5618**	1.4342**	-0.0181	0.1688*	-0.1006	0.1273	0.0780	147	.6277
13	0.5262**	1.3816**	-0.1037	0.1816**	-0.0509	0.0928	0.0429	147	.6370
14	0.4774**	1.3812**	-0.0725	0.1607**	-0.0387	0.1021	0.0301	147	.6414
15	0.4436**	1.3668**	-0.0302	0.1378*	-0.0196	0.0916	0.0608	147	.6468
16	0.4585**	1.3121**	-0.0099	0.1294*	-0.0283	0.1216	0.0384	147	.6134
17	0.5624**	1.3018**	0.0036	0.1196	-0.0683	0.1199	0.0722	147	.5951
18	0.5326**	1.3353**	-0.0301	0.1547*	-0.0102	0.1096	0.0705	147	.6241
19	0.5566**	1.3536**	-0.0520	0.1983**	-0.0445	0.0820	0.0656	147	.6388
20	0.5399**	1.3938**	-0.0595	0.2060**	-0.0626	0.0583	0.0858	147	.6571
21	0.5272**	1.3909**	-0.0870	0.2225**	-0.0715	0.0446	0.0934	147	.6506
22	0.5135**	1.4067**	-0.1017	0.2053**	-0.0685	0.0355	0.0918	147	.6436
23	0.4873**	1.4446**	-0.1423	0.1843**	-0.0785	0.0393	0.0666	147	.6386
24	0.4536**	1.4523**	-0.1466	0.1753**	-0.0807	0.0437	0.0259	147	.6286

[a] A single asterisk (*) denotes the associate regression coefficient was different from zero at the 10 percent level of significance; a double asterisk (**), at the 5 percent level.

TABLE 6-6 ESTIMATED HOURLY REGRESSION COEFFICIENTS, SAMPLE SIZE, AND REGRESSION R-SQUARE FOR JULY WEEKDAY ANALYSIS[a]

Non-SSI

HR	INTERCEP	L_AC	HOTW_USE	L_REFRZ	RANGE	DRY_USE	N	R_SQUARE
1	0.2379	0.5470**	0.0361	0.2124*	0.0845	0.0456	105	.5509
2	0.2364	0.5019**	0.0018	0.2150*	0.0713	0.0332	105	.5034
3	0.1969	0.4605**	0.0010	0.1959*	0.0834	0.0446	105	.5056
4	0.1479	0.3971**	-0.0094	0.1964*	0.1219	0.0607	105	.4656
5	0.1939	0.3451**	-0.0033	0.1781*	0.0721	0.0730	105	.4326
6	0.1682	0.2951**	0.0256	0.2074*	0.1361	0.0287	105	.3092
7	0.0907	0.3033**	0.1371*	0.2377*	0.2369*	-0.0539	105	.3019
8	0.0600	0.3677**	0.1366*	0.3122**	0.2497*	-0.0594	105	.3659
9	0.2224	0.3881**	0.0563	0.2417*	0.1111	0.0519	105	.3857
10	0.2775	0.4309**	0.0338	0.2169	0.0845	0.1224	105	.4134
11	0.2977	0.4558**	0.0090	0.2283	0.1082	0.1577*	105	.4336
12	0.4126*	0.4969**	0.0223	0.2032	0.0474	0.1506*	105	.4465
13	0.4854**	0.5457**	0.0080	0.1779	0.0046	0.1899**	105	.5183
14	0.4917**	0.6166**	0.0013	0.1654	0.0138	0.1799**	105	.5467
15	0.6086**	0.6344**	-0.0068	0.0830	-0.0379	0.2364**	105	.5754
16	0.5998**	0.6595**	-0.0145	0.1124	-0.0630	0.2676**	105	.6191
17	0.5920**	0.6250**	0.0082	0.1360	-0.0060	0.2508**	105	.5895
18	0.5124**	0.6422**	0.0362	0.1801	0.0803	0.2120**	105	.6081
19	0.5477**	0.6536**	0.0264	0.2062	0.0696	0.1778**	105	.5992
20	0.5768**	0.6411**	0.0233	0.1933	0.0575	0.1498*	105	.5797
21	0.5213**	0.6174**	0.0389	0.2270*	0.0048	0.1429*	105	.5984
22	0.4859**	0.5605**	0.0962	0.2328*	-0.0208	0.1582**	105	.5734
23	0.4777**	0.5331**	0.1393*	0.2323*	-0.1151	0.1482*	105	.5423
24	0.4229**	0.5368**	0.0889	0.2040	-0.0594	0.1042	105	.5234

SSI

HR	INTERCEP	L_AC	HOTW_USE	L_REFRZ	RANGE	DRY_USE	N	R_SQUARE
1	0.1397	0.4201**	0.0959	0.2106**	0.0676	0.0734	122	.2631
2	0.1510	0.3734**	0.0919	0.1872**	0.0383	0.0768	122	.2609
3	0.1425	0.3057**	0.0698	0.1826**	0.0385	0.0995*	122	.2737
4	0.1445*	0.3041**	0.0571	0.1737**	0.0233	0.1088*	122	.2862
5	0.1009	0.3413**	0.0640	0.1913**	0.0401	0.1101*	122	.3422
6	0.1205	0.2057	0.0874	0.2042**	0.0493	0.0972	122	.2564
7	0.1584*	0.1751	0.0880	0.1977**	0.0906	0.0617	122	.2302
8	0.1804*	0.3086**	0.0971*	0.1977**	0.1203*	0.0449	122	.3071
9	0.1895*	0.5297**	0.1503**	0.2015**	0.0834	0.0792	122	.3979
10	0.2714**	0.6449**	0.1530**	0.1563*	0.0748	0.1157*	122	.4225
11	0.3604**	0.7070**	0.1513**	0.1401*	0.0175	0.1178*	122	.3875
12	0.3562**	0.8194**	0.1323*	0.1875*	0.0210	0.0830	122	.4006
13	0.3652**	0.8798**	0.1734**	0.2064**	-0.0442	0.0794	122	.4303
14	0.3116**	0.9902**	0.1185*	0.2605**	-0.0247	0.0704	122	.4706
15	0.3056**	1.0147**	0.1187*	0.2866**	-0.0202	0.0400	122	.4727
16	0.2823**	1.0168**	0.1213*	0.3127**	-0.0059	0.0626	122	.4721
17	0.3090**	1.0541**	0.1229*	0.3012**	0.0009	0.1093	122	.4884
18	0.3331**	1.0007**	0.1100	0.3046**	0.0033	0.1132	122	.4743
19	0.2820**	1.0201**	0.1288*	0.3051**	0.0220	0.0994	122	.5073
20	0.2456**	0.9662**	0.1187*	0.2916**	0.0453	0.0986	122	.4961
21	0.2658**	0.8515**	0.1079*	0.2718**	0.0276	0.1252*	122	.4919
22	0.2742**	0.7160**	0.1203*	0.2592**	0.0420	0.0995	122	.4243
23	0.1847*	0.5985**	0.1518**	0.2395**	0.0699	0.0817	122	.3786
24	0.1426	0.5333**	0.1340*	0.2385**	0.0582	0.0962	122	.3378

[a] A single asterisk (*) denotes the associate regression coefficient was different from zero at the 10 percent level of significance; a double asterisk (**), at the 5 percent level.

in L_AC is larger within the range of L_AC for SSI households than it is within the broader range of the L_AC for non-SSI households.

Considerable hourly and monthly variability was exhibited by these AC coefficients, but they were generally larger in the winter than in the summer. This is because the water heater must work harder in cold weather than in warm weather to maintain the desired hot water temperature. In the winter, the coefficients for both groups of customers were always significantly positive, while in the summer significance was attained from about 7 a.m. to midnight for the SSI class and only from 6 a.m. to 9 a.m. for the non-SSI class.

The pattern of coefficients of L_REFRZ for SSI customers, showing significance for virtually all hours in the summer and for very few hours in the winter, reflects the relationship that refrigerator and freezer electricity demands are greater when the household temperature is higher (i.e., in the summer). For non-SSI customers, a similar pattern existed except that for the hottest months the significance declined, perhaps because the extra air-conditioning usage reduced the share of refrigerator-freezer usage below a statistically detectable level.

The RANGE coefficients tended to be nonsignificant, with the following exceptions: breakfast hours during June and July for non-SSI customers, breakfast and lunch hours from October through December for SSI customers, and lunch and dinner hours from October through December for non-SSI customers. The patterns of significance were roughly the same for weekdays and weekends.

The coefficients on the DRY_USE variable had distinctly different patterns of significance for each group. For the SSI group, significance occurred only in the morning and early afternoon hours and only in the summer and fall. The coefficients from the non-SSI regressions were significant mainly in the afternoon and evening hours in the winter as well as in the summer and fall.

For all winter months the L_HEAT coefficients were statistically significant during all hours of the day. The magnitude of the SSI coefficients tended to be nearly twice that of the non-SSI coefficients. About 57 percent of the non-SSI electric heat customers had wood stoves, while only about 11 percent of the SSI electric heat customers had wood stoves, which increases the relative difference in the coefficients. The SSI class had older, less expensive homes than the non-SSI class and, as a result, probably had poor insulation. The size of the coefficient may also be influenced by the construction of the L_HEAT variable that incorporated the house size and thus limited the range of the variable for the SSI customers. There may also be behavioral differences in desired thermostat settings that influence the coefficient.

The WST variable was only important in the non-SSI analysis since such a small percentage of SSI customers with electric heat also had a wood stove. The WST coefficients were significant for nearly all hours of the non-SSI regressions while significance was almost never attained for WST in the SSI regressions. As expected, the magnitude of the significant non-SSI WST coefficients was greatest during the coldest months (December and January) and during the coldest hours (midnight to 10 a.m.) of each month.

6.3.2 Predicted Non-SSI and SSI Population Load Curves

The estimated population means developed in Chapter 5 were used to evaluate the estimated regressions to give predicted per-household load curves for the non-SSI and SSI customer classes. These same load curves were estimated in Chapter 4 via a weighted means analysis. By controlling for variations in usage due to variation in household appliance and demographic mixes, it is conceivable that the precision of the predictions developed here will be greater than that of the predictions developed in Chapter 4. To some extent this will depend on how much precision is lost due to differences between the sample means and the weighted population means of the independent variables.

For both weekday and weekend usage for each of the 10 months, 24 sets of regressions were estimated. Peak day and "near-peak" day usage was estimated in July and January. Estimated bad curves are shown only for July and January weekdays (Table 6-7). Each table provides estimates of the hourly non-SSI and SSI per-household loads, their standard errors, 95 percent confidence limits, the differences in the hourly load estimates, and the standard errors of these differences.

The monthly predicted loads from the covariance analysis are similar to those from the weighted means analysis. For each month, however, the predicted non-SSI loads from the covariance analysis are slightly less than those given by the comparative analysis of the means. The percentage difference ranges from 0 to 30 percent and is nearly always proportional to the magnitude of the predicted load. In the peak hour of the peak winter day, the comparative analysis estimated that the average non-SSI customer used 3.46 kWh, while the estimate for the covariance analysis was 2.49 kWh, a differ-

TABLE 6-7. PREDICTED HOURLY PER HOUSEHOLD LOADS FOR NON-SSI AND SSI POPULATIONS

	Non-SSI				SSI					Std. Error
	kWh	Std.	95% Conf. Limits		kWh	Std.	95% Conf. Limits		Difference[a]	of
Hour	Mean	Error	Lower	Upper	Mean	Error	Lower	Upper	(Non-SSI/SSI)	Diff.
JULY WEEKDAYS										
1	1.1504	0.0696	1.0251	1.2980	0.6230	0.0463	0.5342	0.7156	0.5353**	0.0836
2	1.0150	0.0649	0.8907	1.1452	0.5613	0.0403	0.4839	0.6417	0.4537**	0.0764
3	0.9052	0.0574	0.7952	1.0202	0.5193	0.0358	0.4504	0.5907	0.3859**	0.0677
4	0.8385	0.0555	0.7321	0.9497	0.4808	0.0329	0.4175	0.5463	0.3576**	0.0645
5	0.8094	0.0526	0.7065	0.9146	0.4699	0.0313	0.4094	0.5323	0.3395**	0.0612
6	0.9014	0.0633	0.7004	1.0284	0.5394	0.0303	0.4657	0.6158	0.3620**	0.0739
7	1.1306	0.0772	0.9833	1.2859	0.6324	0.0396	0.5561	0.7115	0.4982**	0.0868
8	1.3005	0.0851	1.1381	1.4718	0.7265	0.0394	0.6505	0.8051	0.5740**	0.0938
9	1.2030	0.0805	1.0495	1.3649	0.7879	0.0443	0.7027	0.8762	0.4151**	0.0918
10	1.2885	0.0919	1.1137	1.4738	0.8741	0.0479	0.7820	0.9696	0.4144**	0.1036
11	1.4171	0.1023	1.2227	1.6237	0.9307	0.0532	0.8285	1.0371	0.4863**	0.1153
12	1.5628	0.1079	1.3578	1.7808	0.9884	0.0570	0.8791	1.1024	0.5744**	0.1220
13	1.6468	0.1060	1.4451	1.8605	0.9963	0.0582	0.8846	1.1128	0.6505**	0.1209
14	1.6640	0.1077	1.4592	1.8613	0.9539	0.0563	0.8460	1.0665	0.7101**	0.1215
15	1.7043	0.1086	1.4977	1.9233	0.9901	0.0579	0.8790	1.1061	0.7142**	0.1231
16	1.7629	0.1084	1.5565	1.9814	1.0250	0.0616	0.9070	1.1485	0.7379**	0.1247
17	1.9645	0.1195	1.7372	2.2054	1.0902	0.0649	0.9660	1.2202	0.8742**	0.1359
18	2.1237	0.1221	1.8912	2.3697	1.1290	0.0657	1.0031	1.2607	0.9947**	0.1387
19	2.2045	0.1247	1.9670	2.4557	1.0784	0.0611	0.9612	1.2008	1.1261**	0.1368
20	2.1404	0.1206	1.9107	2.3833	0.9978	0.0575	0.8875	1.1127	1.1427**	0.1336
21	1.9697	0.1060	1.7659	2.1844	0.9559	0.0526	0.8549	1.0609	1.0138**	0.1190
22	1.9916	0.1100	1.7817	2.2130	0.9684	0.0542	0.8643	1.0767	1.0232**	0.1227
23	1.8365	0.1070	1.6326	2.0518	0.8311	0.0516	0.7320	0.9343	1.0054**	0.1188
24	1.5073	0.0901	1.3352	1.6886	0.7152	0.0500	0.6193	0.8153	0.7921**	0.1031
JANUARY WEEKDAYS										
1	1.2904	0.0881	1.1226	1.4678	0.6414	0.0557	0.5349	0.7533	0.6490**	0.1042
2	1.2275	0.0859	1.0639	1.4006	0.6107	0.0547	0.5061	0.7205	0.6168**	0.1018
3	1.1920	0.0860	1.0283	1.3653	0.5990	0.0534	0.4968	0.7062	0.5930**	0.1012
4	1.1845	0.0870	1.0190	1.3598	0.5829	0.0512	0.4850	0.6856	0.6015**	0.1009
5	1.2251	0.0909	1.0523	1.4084	0.6108	0.0531	0.5091	0.7174	0.6143**	0.1053
6	1.4388	0.1021	1.2448	1.6449	0.7047	0.0566	0.5965	0.8182	0.7341**	0.1167
7	1.8157	0.1289	1.5715	2.0766	0.8306	0.0607	0.7145	0.9524	0.9851**	0.1424
8	2.0236	0.1460	1.7476	2.3197	1.0500	0.0738	0.9091	1.1985	0.9736**	0.1636
9	1.7159	0.1232	1.4825	1.9653	1.1277	0.0742	0.9860	1.2767	0.5883**	0.1438
10	1.6717	0.1139	1.4553	1.9019	1.0881	0.0712	0.9519	1.2311	0.5836**	0.1344
11	1.6267	0.1096	1.4104	1.8479	1.0938	0.0705	0.9591	1.2353	0.5320**	0.1303
12	1.6066	0.1052	1.4065	1.8108	1.0780	0.0681	0.9477	1.2145	0.5287**	0.1253
13	1.5464	0.0993	1.3574	1.7464	1.0043	0.0627	0.8842	1.1300	0.5421**	0.1174
14	1.4866	0.0947	1.3061	1.6774	0.9279	0.0586	0.8156	1.0454	0.5587**	0.1114
15	1.4221	0.0902	1.2501	1.6036	0.8784	0.0556	0.7718	0.9896	0.5437**	0.1059
16	1.4240	0.0801	1.2708	1.5846	0.9266	0.0585	0.8144	1.0437	0.4974**	0.0992
17	1.6132	0.0891	1.4429	1.7921	1.0609	0.0644	0.9375	1.1901	0.5523**	0.1100
18	1.8754	0.0938	1.6959	2.0635	1.1269	0.0663	1.0000	1.2597	0.7485**	0.1148
19	2.0639	0.1017	1.8693	2.2681	1.1147	0.0655	0.9892	1.2459	0.9493**	0.1210
20	2.0298	0.1063	1.8268	2.2434	1.0223	0.0620	0.9036	1.1464	1.0075**	0.1230
21	1.9549	0.1064	1.7519	2.1688	0.9702	0.0619	0.8515	1.0943	0.9848**	0.1231
22	1.8931	0.1072	1.6888	2.1088	0.9057	0.0607	0.7894	1.0274	0.9875**	0.1232
23	1.7393	0.1060	1.5375	1.9520	0.7969	0.0582	0.6856	0.9135	0.9424**	0.1209
24	1.4858	0.0934	1.3078	1.6738	0.7174	0.0560	0.6103	0.8297	0.7684**	0.1089

[a] A double asterisk signifies that the difference is statistically significant at the 5% significance level.

ence of 28 percent. On the other hand, for this same hour of the average September weekday, the means analysis predicted an average usage of 1.37 kWh, while the covariance analysis predicted 1.26 kWh, a difference of just 8 percent.

Both analysis methods produced nearly identical predictions of average per-household SSI-customer usage in all months. This suggests that the discrepancy between the methods is due to differences in predicted non-SSI usage. There was virtually no difference in the standard errors of the estimates given by each procedure for both the SSI and non-SSI estimates, which suggests that the additional precision obtained in the covariance analysis by controlling for cross-sectional appliances and demographic differences was just offset by the loss of precision incurred by evaluating the regressions at the weighted, rather than the sample, means.

The main benefit provided by the covariance results is that it indicates that sensible load estimates can be obtained from the regression equations when they are computed at values of the independent variables that are in some cases quite different from the sample means. Table 5-3 presented in Chapter 5, illustrates the magnitude of these differences. As a consequence of this "resiliency" of the regression equations, the analyses of individual rate classes and low-usage customers that follow can be approached with greater confidence.

6.3.3 <u>Comparisons Within Individual Rate Classes</u>

Consumption of non-SSI and SSI customers by rate class has already been predicted in the comparison of weighted means analysis of Chapter 4, which showed that percentage differences between usage of non-SSI and SSI customers tended to be smaller within rate classes than for all rate classes combined. Individual rate class means were estimated using only individuals belonging to the rate class under consideration. However, when these within-rate-class comparisons are made using the covariance analysis results, the entire sample of customers figures into the calculations. This is because the entire sample was used to estimate the regression relationships. The individual rate class samples are only used to obtain within-rate-class covariate means for use in evaluating the estimated regressions.

The resulting non-SSI and SSI load estimates for the R, RA, and RW rate classes show similar percentage differences to those found in the comparative analysis. Table 6-8 illustrates the similarities between these results and those found in Chapter 4, by comparing the percentage differences in total consumption between non-SSI and SSI customers for each rate class found by each analysis method.

The results of the covariance analysis confirm the finding of the comparative analysis that, in general, percentage differences within rate classes are not as large as they are for the combined population. The actual percentage differences estimated by the covariance analysis for July were remarkably close to those computed from the comparative analysis. The January percentage differences, however, were not as close, being smaller for the RA and RW classes and larger for the R class.

6.4 COMPARISON OF USAGE BETWEEN SSI AND "LOW USE" CUSTOMERS

The analysis of covariance permits usage of the two customer classes to be compared, controlling for differences in appliance saturations and other household characteristics. By using a common set of covariate values to evaluate both the non-SSI and SSI regressions, the difference found in the resulting load estimates of non-SSI and SSI customers can be attributed to behavioral differences between the two groups (assuming the validity of the regression models).

TABLE 6-8. COMPARISON OF PERCENTAGE DIFFERENCES IN TOTAL DAILY CONSUMPTION BETWEEN SSI AND NON-SSI CUSTOMERS FOUND BY WEIGHTED MEANS ANALYSIS AND COVARIANCE ANALYSIS

Rate Class	July 1980 Weighted Means Analysis	July 1980 Covariance Analysis	January 1981 Weighted Means Analysis	January 1981 Covariance Analysis
R	33	33	17	24
RA	50	49	22	8
RW	38	36	43	36
All	49	45	59	45

The load analyses have shown that non-SSI customers use more electricity than SSI customers in all three rate classes, in all months and in every hour of the day, with the only exception occurring between non-SSI and SSI RA customers in some January daytime hours. It is not known, however, to what extent the predominantly greater non-SSI usage is due to a higher saturation of appliances, larger homes, etc., and to what extent it is due to greater appliance utilization rates.

The objective of this section is to determine if the label "low use" often applied to the SSI class can be interpreted to mean that a typical SSI customer will use appliances less than a typical non-SSI customer, or whether the correct interpretation is simply that the typical SSI household uses relatively little electricity because they have fewer appliances.

To shed some light on this question, the weighted means of the independent variables computed for the SSI class were inserted into the regression equation estimated for the <u>non-SSI customers</u> to predict what the typical non-SSI load would be if that class had the same appliance and demographic mix as the SSI class. The exercise was conducted using the overall SSI population means and also the three individual SSI rate class means. The four sets of means are shown in Table 6-9. The appliances for which major differences in saturation occurred among the rate classes were the water heater and electric heat since the rates were defined according to ownership of these appliances.* In addition to the water heater and primary electric heat variables, the RA class generally has higher saturations of the other

*Recall that the estimated 34.2 percent saturation of electric water heaters in the R class is due mainly to customers having water heaters too small to qualify them for the RW rate and also to the failure of certain customers who acquired (qualifying) water heaters to identify themselves to the utility prior to the time the survey was conducted.

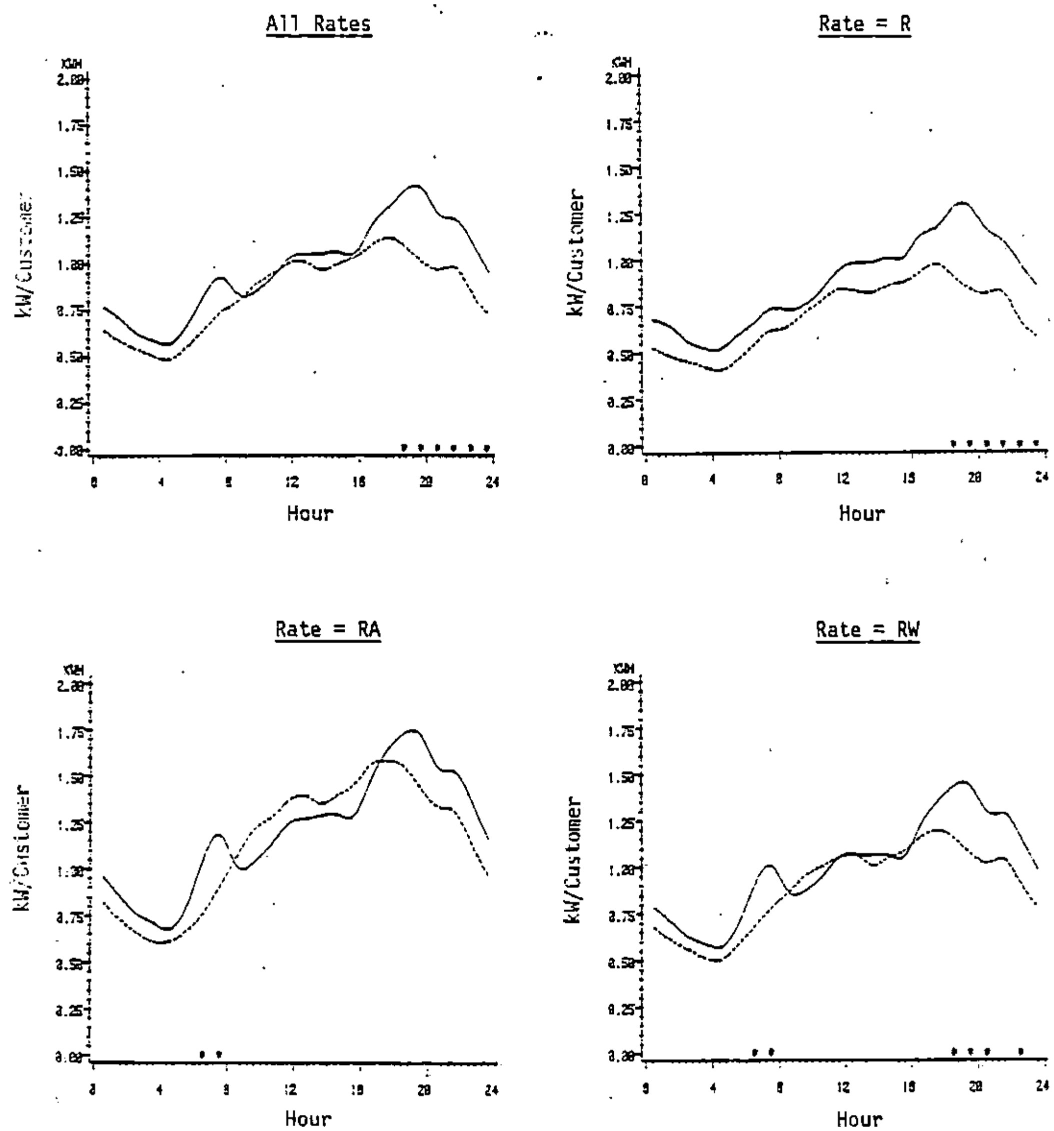
TABLE 6-9. APPLIANCE SATURATIONS AND DEMOGRAPHIC CHARACTERISTICS BY RATE CLASS FOR SSI POPULATION

Variable	Weighted Mean			
	R	RA	RW	Combined
CAC	.006	.254	.023	.029
WAC	.151	.289	.174	.172
HEATPUMP	.000	.140	.000	.007
EL_FURN	.000	.201	.000	.011
RM_BY_RM	.003	.594	.003	.035
HOTW	.342	.997	.892	.709
REFRZ	1.617	1.700	1.712	1.679
RANGE	.650	.966	.879	.805
WASH	.449	.596	.475	.473
DRY	.095	.251	.164	.145
DISH	.001	.100	.001	.006
WST	.233	.081	.250	.235
NOHHMEM	1.689	1.775	1.659	1.676
SIZE_RES	.745	.865	.980	.894

appliances as well. This is especially true for central air conditioning, where the RA saturation is estimated to be 25.4 percent as opposed to 2.3 percent for the RW class and just 0.6 percent for the R class. These differences must be kept in mind when interpreting the results among the three rate classes.

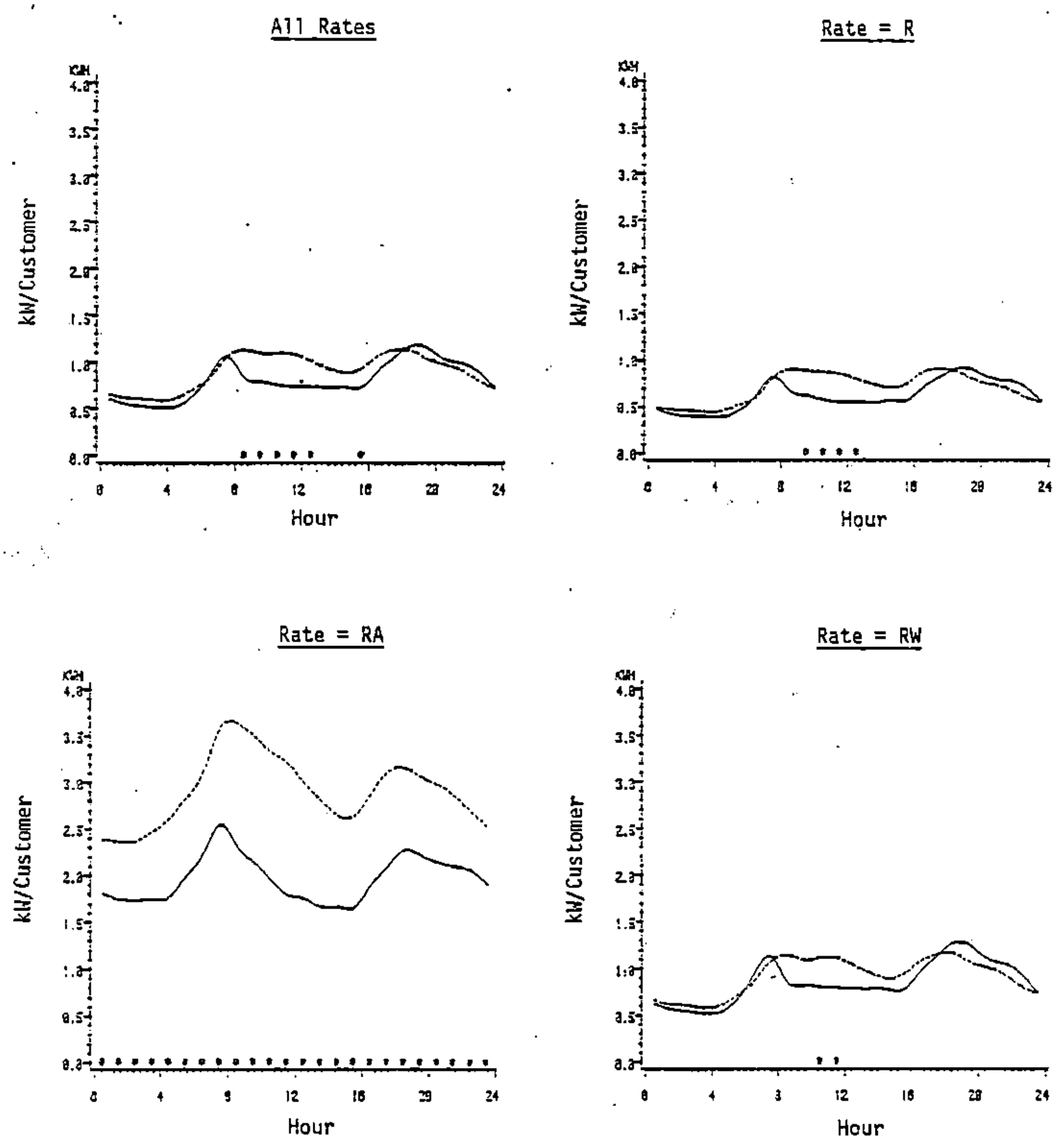
The results of comparing the utilization habits of SSI and non-SSI customers on a rate by rate basis are shown in Figures 6-1 and 6-2. The July analysis for the combined rate classes indicates that the groups use electricity at nearly the same rate except from 6 p.m. to midnight when non-SSI utilization is significantly greater. The individual rate classes reveal more variability between the utilization rates of non-SSI and SSI customers. Assuming an appliance and demographic mix corresponding to that of the SSI R-rate population yields consistently positive differences between non-SSI and SSI utilization, again with the largest differences occurring from 6 p.m. to midnight.

The comparisons, however, are quite different for RA type customers. In this case the only significant positive differences occur in the morning, from 6 a.m. to 8 a.m. Significant differences were found for no other hours, but from 8 a.m. until 5 p.m. SSI utilization was predicted to be greater than non-SSI utilization for this mix of customers. The trend reversed itself in the evening. Many of the positive (5 p.m.-12 p.m.) and negative (8 a.m.-5 p.m.) differences, while not significant at the 10 percent level, were still greater than zero by more than one standard deviation. Comparisons generated by assuming identical mixes of RW customers showed significantly greater non-SSI utilization in the morning (6 a.m.-8 a.m.), in the evening (6 p.m.-10 p.m.), and 11 p.m. to midnight. The daytime differences were again mostly negative, but very nearly zero.



Key: ——— Non-SSI
------ SSI
\# Denotes statistically significant differences in the estimated hourly loads at the 10 percent level of significance

Figure 6-1. Comparison of estimated hourly usage of SSI and "Low-Use" customers — July weekdays.



Key: ——— Non-SSI
------ SSI
# Denotes statistically significant differences in the estimated hourly loads at the 10 percent level of significance

Figure 6-2. Comparison of estimated hourly usage of SSI and "Low-Use" customers — January weekdays.

An explanation for the three different ways in which non-SSI and SSI utilization compared may be that more SSI customers are home during the day (9 a.m.-5 p.m.) so that their use of the discretionary appliances (range, washer, dryer, dishwasher) is spread fairly evenly throughout the day and their use of air conditioning must occur in the daytime as well as nighttime hours. If so, then relatively fewer non-SSI customers are home during the day so that they would tend to concentrate their usage of discretionary appliances in the morning and evening hours. This would explain the significant positive utilization differentials detected during the morning and evening hours for R and RW households, as well as the negative differentials found for the RA customer comparisons (since they would use less air conditioning during the daytime hours).

The results for January are quite interesting. For the three rate classes combined, SSI usage is estimated to be significantly greater than non-SSI usage from 8 a.m. to 1 p.m. and from 3 p.m. to 4 p.m. when evaluating the regressions at the SSI means. In the remaining hours the differences are not significant. The sign pattern, however, is negative (indicating greater SSI usage) for all hours except 6 a.m. to 8 a.m. and 6 p.m. to 11 p.m. The comparisons within rate classes show that the combined results are very similar to those for the R and RW rates and much different from those for the RA rate.

The lack of influence of the RA results on the combined rate results is due to the small proportion of SSI customers on the RA rate (only 5.3 percent of the total SSI population). The results, however, indicate that usage of SSI households on the RA rate is significantly greater than usage of non-SSI households on the RA rate during all hours of the day in January. Possible explanations for these differences are a lower saturation of wood stoves, a preference for warmer household temperatures, and more poorly insulated homes within the SSI class in comparison to the general population.

The significantly higher estimated usage in the daytime by the R and RW customers may again be reflective of a relatively larger portion of the SSI class being at home during these hours. This hypothesis is supported by comparing the shapes of the estimated load curves of the SSI and non-SSI customers. The SSI customers consume electricity at a fairly constant rate from 7 a.m. to 8 p.m. whereas the non-SSI customers have an early morning peak from 7 a.m. to 8 p.m. and an evening peak from 5 p.m. to 11 p.m.

7.0 COST ANALYSIS OF LOAD DIFFERENCES

The primary objective of this chapter is to translate the differences between SSI and non-SSI customer usage that were presented in the comparative analysis of Chapter 4.0 into differences in the Duke Power system energy costs. To accomplish this objective, an analysis framework that describes a utility's cost in terms of marginal and average energy costs has been developed.

A major assumption is that the differences in capital costs and costs associated with transmission and distribution are of lesser consequence than those of energy costs, which implies that the cost estimates represent a conservative estimate of the total difference in the cost of serving SSI and non-SSI customers. The costing procedure will show the relative magnitude of the energy cost differences, which is essential to determine if the SSI rate is cost-justified.

Section 7.1 presents an overview that highlights various costing methodologies and illustrates both the theoretical and empirical problems associated with the methodologies. The data compilation and reduction procedures used in the costing analysis are discussed in Section 7.2. The methodology used in the cost analysis is developed in Section 7.3 and the results are presented in Section 7.4.

7.1 OVERVIEW OF COSTING METHODOLOGIES

In recent years researchers in electricity economics have devoted considerable attention to the issue of the most appropriate measure of the cost of producing electricity. No clear consensus has been reached but a pragmatic interpretation of the relevant issues will provide a much needed background for the methodology employed in this chapter to assess the cost implications of the differences between SSI customers and non-SSI customers.

Embedded or average cost and marginal cost approaches are the two primary classifications, or methodologies, for measuring the cost of producing electricity. Average cost techniques focus primarily on the recovery of the investment and operating costs incurred in the production of electricity. Marginal cost techniques measure the incremental or additional cost of producing one more unit of electricity. Average cost reflects the cost of producing electricity averaged or weighted over an entire time period; marginal costs are forward looking, sending signals to producers and consumers based on the most recent unit produced.

Unfortunately, average cost versus marginal cost has become a hotly debated issue in which proponents of each technique argue the significance of following their method. This discussion is blurred even more by arguments among the proponents of each methodology as to the appropriate (correct) interpretation of the theoretical concepts that are the underpinnings of each approach.

Average cost techniques combine the capital cost of previously purchased equipment, the cost of new investment, and the variable costs of producing electricity--fuel, operation, and maintenance--into a comprehensive measure of the cost of producing electricity. The primary concern of average cost techniques is to provide a method to recover the costs of producing electricity. Variable costs are easily allocated to the units responsible, even differentiated by the time that they were incurred. The main problem in electricity pricing is to allocate the capital costs that are common to all customers. The average cost methods divide customers into broad classes and then allocates costs across these classes according to various criteria. Table 7-1 summarizes the most frequently used criteria for allocating capital costs.

The peak responsibility method allocates demand costs for an electric utility on the assumption that capacity requirements are determined by the peak load. Capital costs are allocated either totally to the demand component or are adjusted to compensate for those customer classes that have higher load factors and impose lower costs. These additional measures recognize the effect on total capacity requirements of maintenance scheduling and other system operation factors in addition to the importance of the peak load. The range of measures will also indicate any sensitivity to the system load characteristics.

The effectiveness of the peak responsibility method for allocating demand-related costs is hindered by the fact that it does not provide any benefit to the positive impacts of load diversity and by the major shifts in cost allocation that arise when peaks shift. The former effect is mitigated by using peak averages and the latter can be reduced by using the load factor excess demand adjustment to account for diversity.

The average of the maximum demands combines maximum class demands, calculates their average, and uses this average to allocate capital costs. Noncoincident demand techniques use the group maximum demands that do not occur at the same time the system maximum occurs. Both of these techniques can be adjusted in the same way as the peak responsibility technique to incorporate the benefits of diversity.

TABLE 7-1. CRITERIA FOR ALLOCATING CAPITAL COSTS

1. Peak responsibility
    a. 100% to demand component
    b. Load factor--excess demand
2. Average of maximum demands
    a. 100% to demand component
    b. Load factor--excess demand
3. Noncoincident demand
    a. 100% to demand component
    b. Load factor--excess demand
    c. Load factor--diversity factor

Four basic shortcomings limit the usefulness of the average or embedded cost techniques. The methods reflect a primary accounting goal of recovering sunk costs, imply that resources can be used in the future as in the past, consider equity in the very narrow terms of an allocated share of accounting cost, and provide no incentive effects. Turvey and Anderson (1977) have pointed out that the relevant costs for efficiently allocating resources are the additional costs of meeting extra usage. The costs should be a signal that is related to the value of the resource used or saved. Primarily, prices should be forward looking.

Marginal costs overcome the primary weaknesses of the average cost techniques by providing signals that are forward looking and reflect the existing situation in the marketplace and that of the electric utility itself. Marginal costs, however, present the analyst with a perplexing array of problems that limit their widespread application in utility rate design.

Marginal cost is the cost incurred by producing one more unit or the cost avoided by producing one less unit. Economic efficiency requires that marginal costs should equal prices because the incremental value that consumers place on a unit should just be equal to the additional opportunity cost incurred in producing that unit. Marginal cost equal to price should also serve as a rule of thumb for the electric utility in that it pays the utility to continue to produce and sell as long as incremental revenues cover incremental costs.

Economic efficiency is not an equity criterion and provides no implications for the fairness of an existing distribution of income. In theoretical terms, if marginal cost pricing is not achieved in all markets, economic welfare may not improve by achieving it in one market. From a practical policy perspective, however, regulators who encourage movements toward marginal cost pricing will improve efficiency within the regulatory arena that they govern.

Problems also arise in defining marginal costs, which, in turn, has lead to numerous interpretations in an attempt to solve these problems. In a recent series of works,* several analysts compared and critiqued the alternative methodologies for implementing marginal cost pricing for an electric utility. We will draw from this work to illustrate the problems in defining marginal costs but will not provide a detailed critique of each method.

To carry out a marginal costs analysis, one must specify the time perspective that is relevant. Marginal costs consider only those costs that are variable and ignore the costs that are already sunk into the enterprise. The length of the selected time horizon will determine the percentage of costs that are variable and thus are included in the analysis.

In specifying the length of the time horizon, most of the major marginal cost techniques have tended to define the time horizon to allow changes in plant capacity, arguing that long-run marginal costs are a more workable measurement. Short-run marginal costs, which do not allow for changes in plant capacity, have high variability and may yield the electric utility

*Two of the most relevant works are Temple, Barker, Sloan. An Evaluation of Four Costing Methodologies, Electric Power Research Institute (EPRI). Electric Utility Rate Design Study (Report #66), July 13, 1979 and the Comments on an Evaluation of Four Costing Methodologies, by Temple, Barker Sloan, et al., EPRI, Electric Utility Rate Design Study. (Report #67), June 12, 1980.

revenues that are either too high or too low. The Cicchetti, Gillen and Smolensky (CGS) method employs the long-run marginal cost definition arguing that in a "planning" sense, capacity can be varied and is fixed only when viewed as "bricks and mortar."

The Ernst and Whinney method assumes that all factors of production are flexible and that any new technology can be incorporated into the cost analysis. Utilities are assumed to have full adaptability and are not restricted to using capacity from the preceding period. This method is less valuable as a practical means of measuring marginal cost than as a means of comparing the idealized marginal costs of two different production strategies.

The National Economic Research Associates (NERA) method and the Gordian Associates (Gordian) method constrain the utilities to their current expansion plans for a relevant time horizon for costing, but draw heavily on personal expertise rather than rigorous definitions for their methods. The Gordian model, however, allows for up to 100 different future expansion plans and compares the discounted costs of each in order to select that plan with the lowest discounted costs of producing the predicted future demands.

Turvey and Anderson (1977) suggests that from a practical standpoint, defining the time horizon is not a major problem. Prices should reflect both long-run and short-run marginal costs to the extent that each is important for the utility or policymaker. If long-run signals are more important, then greater weight should be given to the long-run cost measure and vice versa.

Marginal cost techniques must also solve the problem of specifying the appropriate incremental unit. CGS solves this problem by specifying the incremental unit as the change in the timing of expansion planned by a utility attributable to an increase in production. NERA, on the other hand, defines the marginal unit as the next combustion turbine that is brought on line by an increase in output. It is clear that in solving this problem the analyst must balance the practical with the theoretical ideal.

Marginal cost analyses must still find some means of allocating the costs that are common and that cannot be easily attributed to a customer. This involves defining a peak period and then developing a rationale for allocating the common costs (primarily capital costs) across the peak period. Problems that arise here are very similar to the capital allocation problems that plague embedded cost analyses.

In summary, there are problems in employing either marginal costs or average costs to determine the appropriate prices for electricity. Marginal costs do provide important signals to producers and consumers that are disguised in average cost estimates, which is critical from the rate design standpoint. For the purposes of this chapter, however, both provide a rationale for developing a practical methodology to portray the cost differences between SSI and non-SSI customers.

7.2 DATA COMPILATION AND REDUCTION

Hourly load data of Duke Power Company for the period June 1980 through March 1981 (summarized in Section 3.1) were the main source of data for this analysis. Detailed information on Duke Power production capability, including plant capacity, fuel use, heat rate, and production cost for the units, was provided by Duke Power for inclusion in the GLiMPS production costing model. GLiMPS is a power system production costing model that estimates costs based on sequential hourly simulation of the system's operation. The SSI rate study used a modified version of GLiMPS that minimized the operational costs but still produced reliable production costing results. This version modified the Monte Carlo simulation of the power system stochastics and used 20 production histories in simulating production costs.

GLiMPS determines optimum daily operating configurations at hourly intervals using unit commitment and economic dispatch criteria. GLiMPS uses an optimal unit commitment subroutine to determine the hourly operating schedule of available units. Standard utility dynamic programming techniques that consider starting cost and operating cost provide the basis for the unit commitment process. Variable operating and maintenance costs are not considered because they are small compared to fuel costs. Unit loading and fuel costs are determined by the LaGrange multiplier economic dispatch method that provides a cost minimum operation decision.

GLiMPS estimates the hourly production for an average weekday and an average Saturday and Sunday. A simple average of Saturday and Sunday costs was calculated to provide an estimate comparable with the usage data for an average weekend day from the comparative analysis.

The GLiMPS model dispatches only conventional fuels and does not provide for any hydro capability. Because the Duke System has substantial hydro capability, a linear programming routine was employed to adjust the system load data by using the pumped hydro to shave the peaks and fill the valleys in the system load profile. More detailed documentation of this linear programming model is presented in Appendix E.

7.3 METHODOLOGY FOR COSTING ANALYSIS

The basic objective of the costing methodology is to provide a means for expressing the differences in load between non-SSI and SSI customers in terms of the cost of producing electricity. As we have demonstrated earlier, there is no clear consensus on the most appropriate means for accomplishing this task.

The key to developing a workable methodology is to focus on those cost components that are most relevant to differences between SSI and non-SSI customers. Figure 7-1 indicates the possible sources of cost differences and the one chosen for this study.

At the system level, transmission and distribution costs should be essentially the same for the two groups because they require the same equipment and impose the same requirements on the system. Ignoring these sources of potential differences in cost should have little effect on our results. At the substation level, the more diverse load of the SSI customers should result in some small amount of savings, but this analysis is concerned only with system level costs.

Administrative costs should also be essentially the same for the two groups except for the requirement that SSI customers must be identified and verified by Duke Power Company and the Social Security Administration. This is an added cost for Duke, but the order of magnitude is probably small now that program startup costs are sunk, and therefore it is excluded by the costing methodology.

Differences in generation costs should constitute the largest component of the cost differential between serving SSI and non-SSI customers and this is the primary focus of the costing methodology. These differences are due to both capital and energy elements. Differences in capital costs are excluded because of the arbitrary nature of attributing costs of capital to different residential customers and measurement problems in actually determining capital costs. This exclusion suggests that because SSI customers

COST CATEGORIES

	Generation	Transmission	Distribution	Administration
Non-SSI Customers	√	•	•	•
SSI Customers	√	•	•	•

√ Measured by Costing Methodology

• Not Measured by Costing Methodology

Figure 7-1. Costing methodology and cost categories.

use less energy than non-SSI customers and have at least as high a load factor, the costing methodology will provide a lower bound estimate of the difference in the cost of service.

The costing methodology that has been adopted measures the short-run marginal and average energy costs of serving SSI and non-SSI customers. Long-run considerations are excluded because of the small effect the SSI customers have on system load and any system expansion plans. Since short-run energy costs are the largest source of cost differences, the use of these energy costs achieves the primary objective of measuring the cost differential that results from the usage differences between SSI and non-SSI customers.

7.4 RESULTS

Table 7-2 presents the average hourly energy costs for SSI and non-SSI customers for a typical weekday. The same costs for a typical weekend day are presented in Table 7-3. The cost estimates are based on estimated hourly production costs provided by the GLiMPS production costing model and estimated hourly usage from the comparative analysis presented in Chapter 4.

The data indicate that the cost of serving SSI customers, measured in terms of hourly energy costs, are approximately half of those for serving non-SSI customers. The calculated hourly energy costs follow the system load profile for both winter and summer by increasing as the system moves toward peak production. In the off season months, the cost differential is not quite as great, reflecting the smaller difference in usage in these non-critical months.

The average monthly energy costs of a typical weekday and weekend day for this study are presented in Table 7-4. For the typical weekday, average

TABLE 7-2. AVERAGE HOURLY WEEKDAY ENERGY COSTS
SSI AND NON-SSI CUSTOMERS--mils/kWh
(June 1980 - March 1981)

Average cost in	June 1980		July 1980		August 1980		September 1980		October 1980	
	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI
0000-0100	7.95	4.31	12.06	5.76	12.23	6.38	8.49	4.83	7.78	4.44
0100-0200	6.48	3.70	10.11	5.13	10.35	5.58	7.09	4.24	6.84	3.89
0200-0300	5.44	3.22	8.58	4.63	9.15	5.00	6.32	3.96	6.70	3.85
0300-0400	5.23	2.99	7.74	4.27	8.24	4.77	5.99	3.63	6.69	3.74
0400-0500	4.93	3.04	7.25	4.25	7.73	4.94	5.87	4.05	7.20	4.08
0500-0600	6.96	3.93	8.36	4.88	9.04	5.31	7.87	4.67	10.24	4.88
0600-0700	11.12	5.51	11.55	6.10	12.74	6.38	12.13	6.22	16.80	8.25
0700-0800	13.27	7.63	13.70	9.66	14.89	8.50	14.69	8.37	19.54	11.06
0800-0900	11.90	8.18	12.36	8.67	14.00	9.40	11.84	9.16	16.19	11.36
0900-1000	12.07	8.41	13.79	9.72	14.96	10.24	11.07	8.63	15.12	10.39
1000-1100	12.64	8.35	15.86	10.35	16.10	10.80	11.61	8.54	13.89	9.52
1100-1200	12.48	8.51	17.67	10.83	18.34	11.15	12.54	9.23	13.68	9.35
1200-1300	10.96	6.78	16.06	9.39	17.07	10.20	12.13	8.06	11.78	7.46
1300-1400	10.63	6.07	15.74	8.83	17.40	9.86	12.36	7.65	11.01	6.65
1400-1500	10.68	6.07	15.98	9.01	17.97	9.99	12.05	7.66	10.11	6.35
1500-1600	10.98	6.48	16.69	9.23	18.01	10.16	12.51	7.61	10.68	6.72
1600-1700	12.30	7.08	18.23	9.62	20.02	10.72	14.89	8.17	12.46	7.74
1700-1800	14.02	7.33	20.29	9.96	21.65	11.29	17.14	8.77	14.91	8.47
1800-1900	15.75	7.64	21.98	10.15	23.96	11.30	19.35	8.95	17.33	8.81
1900-2000	15.83	7.29	22.10	9.98	23.89	10.75	19.73	9.53	17.87	8.74
2000-2100	15.76	7.54	21.27	9.85	23.95	11.25	19.48	9.65	17.49	8.31
2100-2200	16.92	7.95	22.82	10.43	23.89	11.12	18.30	8.66	17.13	7.41
2200-2300	15.70	6.90	21.75	9.12	21.58	9.70	16.03	7.33	14.70	6.66
2300-2400	12.27	6.06	17.93	7.89	17.92	8.53	12.60	6.22	11.71	5.76

TABLE 7-2 (con.)

Average cost in	November 1980		December 1980		January 1981		February 1981		March 1981	
	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI
0000-0100	12.32	5.15	14.52	5.92	17.92	7.56	16.17	6.73	12.11	6.16
0100-0200	11.41	5.01	13.01	5.50	17.11	7.14	15.43	6.34	11.83	5.69
0200-0300	11.27	4.81	12.61	5.33	16.80	6.98	15.18	5.93	11.78	5.49
0300-0400	11.30	4.80	12.92	5.21	16.97	6.88	15.42	6.04	12.29	5.46
0400-0500	12.46	5.14	13.94	5.59	17.80	7.22	16.00	6.35	12.96	5.81
0500-0600	15.87	6.03	16.85	6.60	21.06	8.46	19.06	7.30	16.30	6.96
0600-0700	22.73	9.25	23.24	8.66	29.26	10.41	27.43	7.82	24.64	9.70
0700-0800	25.38	12.33	26.54	11.45	33.10	13.91	31.11	13.09	26.28	12.28
0800-0900	21.11	12.66	23.11	12.65	26.99	15.29	25.20	13.58	21.17	12.96
0900-1000	19.44	11.73	21.72	11.83	26.04	14.31	22.51	12.53	19.12	11.72
1000-1100	18.00	10.66	20.76	11.03	25.29	14.26	21.60	11.93	18.06	11.19
1100-1200	16.93	10.31	19.70	10.49	24.19	13.81	21.02	11.84	17.06	10.56
1200-1300	14.42	8.35	16.77	8.73	20.62	11.68	17.98	9.67	14.74	8.96
1300-1400	12.87	7.38	15.40	7.94	19.34	10.45	16.94	8.61	13.78	7.89
1400-1500	12.29	7.23	14.54	7.92	18.22	9.64	15.42	8.47	13.04	7.76
1500-1600	12.39	7.39	14.77	8.38	18.19	10.33	16.00	9.08	13.21	8.24
1600-1700	14.90	9.24	17.23	9.71	20.87	11.95	18.23	10.66	14.99	9.57
1700-1800	19.61	10.44	22.94	10.54	25.88	12.98	22.37	11.28	18.89	10.04
1800-1900	23.73	10.97	26.86	11.49	30.84	13.97	28.57	12.56	23.21	10.97
1900-2000	23.06	10.11	26.14	10.99	31.44	13.28	29.99	12.19	24.58	11.25
2000-2100	22.19	9.38	25.19	10.37	30.37	12.62	28.28	11.63	23.62	10.86
2100-2200	21.27	8.79	24.52	9.62	29.01	11.60	27.58	10.79	22.67	9.63
2200-2300	19.70	7.88	22.20	8.54	26.50	10.42	24.75	9.57	19.26	8.56
2300-2400	17.00	6.89	19.12	7.39	22.75	9.38	20.86	8.67	15.85	7.64

TABLE 7-3. AVERAGE HOURLY WEEKEND ENERGY COSTS
SSI AND NON-SSI CUSTOMERS--mils/kWh
(June 1980 - March 1981)

Average	June 1980		July 1980		August 1980		September 1980		October 1980	
cost in	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI
0000-0100	9.45	4.85	12.41	5.64	11.87	6.04	8.31	4.57	8.17	4.29
0100-0200	7.15	4.03	9.91	5.00	9.68	5.27	7.05	4.13	7.59	4.02
0200-0300	6.38	3.70	8.35	4.50	8.43	4.72	6.05	3.64	6.52	3.69
0300-0400	5.72	3.36	7.64	4.17	7.32	4.51	5.50	3.68	6.39	3.65
0400-0500	5.50	3.28	7.04	3.94	7.04	4.45	5.20	3.65	6.45	3.72
0500-0600	5.91	3.36	6.93	4.09	7.08	4.41	5.53	3.95	7.30	3.78
0600-0700	6.89	4.14	7.77	4.82	7.83	4.82	6.40	4.12	8.50	4.93
0700-0800	8.57	5.90	9.47	6.11	9.43	6.30	8.53	5.94	11.18	7.90
0800-0900	11.38	7.51	13.27	7.91	13.03	8.06	11.57	8.15	15.24	10.62
0900-1000	14.80	8.41	16.55	9.59	13.79	9.54	14.06	8.49	17.63	10.57
1000-1100	16.28	8.52	19.14	10.18	18.54	10.57	14.91	8.60	17.28	9.46
1100-1200	17.49	8.53	19.72	10.12	20.50	10.18	15.74	8.55	16.95	9.37
1200-1300	15.73	7.64	18.51	9.64	18.35	9.45	14.65	7.86	16.09	8.14
1300-1400	14.72	7.57	18.16	8.83	17.91	9.21	14.22	7.21	14.21	7.25
1400-1500	15.01	7.11	17.81	8.64	17.53	8.87	14.15	7.11	13.20	6.62
1500-1600	14.38	6.84	18.04	8.09	17.34	8.96	14.62	7.12	13.08	6.83
1600-1700	15.18	6.84	18.83	7.97	17.17	8.70	15.00	7.52	13.39	6.91
1700-1800	16.04	6.88	19.36	8.25	18.02	9.02	15.56	7.49	14.48	7.39
1800-1900	16.46	6.60	18.82	8.71	17.51	8.72	15.77	7.57	14.95	7.81
1900-2000	16.14	6.55	17.65	8.40	17.52	8.37	15.22	7.70	15.10	7.80
2000-2100	16.00	6.83	18.52	8.40	18.02	8.34	16.85	8.37	15.39	7.97
2100-2200	17.09	7.73	19.90	9.15	18.62	9.22	16.08	7.52	15.43	7.09
2200-2300	16.06	6.96	19.24	8.57	17.37	8.11	13.98	6.94	13.85	6.50
2300-2400	14.36	6.36	17.35	7.50	14.79	7.41	11.96	6.18	11.39	5.58

I/A

TABLE 7-3 (con.)

Average cost in	November 1980		December 1980		January 1981		February 1981		March 1981	
	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI	Non-SSI	SSI
0000-0100	12.40	5.16	16.50	6.60	20.08	8.20	16.23	7.04	12.78	6.43
0100-0200	11.20	4.88	15.10	6.00	18.74	7.53	15.41	6.34	11.90	5.56
0200-0300	10.53	4.74	14.07	5.78	18.36	7.11	14.94	6.01	11.59	5.46
0300-0400	10.75	4.56	13.84	5.75	18.14	7.13	14.77	5.95	11.82	5.40
0400-0500	11.24	4.64	15.07	5.74	18.73	7.32	15.11	6.05	12.26	5.47
0500-0600	12.21	5.22	16.24	6.19	19.95	7.73	16.31	6.25	13.90	5.57
0600-0700	13.98	6.27	17.98	7.05	22.86	8.65	18.45	7.11	16.01	7.72
0700-0800	17.19	9.35	22.28	10.11	26.20	12.15	21.56	10.32	19.38	11.00
0800-0900	21.46	11.77	27.07	13.30	30.67	15.46	25.76	12.66	22.82	13.17
0900-1000	23.55	11.72	28.97	13.63	32.16	14.79	26.63	12.00	23.72	12.05
1000-1100	22.68	11.41	27.66	12.78	31.82	15.05	25.38	11.72	22.21	11.46
1100-1200	21.75	10.32	25.97	12.56	30.48	14.63	23.68	12.17	20.61	11.12
1200-1300	19.18	8.98	22.97	10.48	27.61	12.34	21.66	10.81	18.22	9.81
1300-1400	17.02	8.21	21.29	9.61	25.80	11.44	20.54	9.36	16.75	8.74
1400-1500	15.56	7.56	19.56	9.14	24.15	10.90	18.34	8.96	15.16	8.18
1500-1600	15.18	7.61	18.73	8.76	23.68	10.53	17.83	8.91	15.10	7.92
1600-1700	16.14	8.43	20.54	9.27	23.97	10.96	18.40	9.12	15.47	8.12
1700-1800	18.56	8.86	23.15	10.19	27.65	12.19	20.26	9.50	17.23	8.45
1800-1900	19.52	9.17	24.19	10.76	29.61	12.67	22.72	9.97	19.00	9.17
1900-2000	19.14	8.94	24.64	10.93	29.18	12.56	22.64	9.96	20.05	9.64
2000-2100	19.75	8.36	24.90	10.87	29.28	12.70	23.01	9.83	20.31	10.37
2100-2200	18.62	8.02	24.80	10.02	29.45	12.38	21.92	9.46	19.43	9.43
2200-2300	17.17	7.26	22.89	9.13	27.14	10.92	20.21	8.53	17.35	8.65
2300-2400	15.08	6.21	20.83	8.31	24.92	9.90	18.35	8.08	14.96	7.59

TABLE 7-4. AVERAGE MONTHLY ENERGY COSTS FOR NON-SSI AND SSI CUSTOMERS--WEEKDAYS AND WEEKENDS

Month/year	Average weekday cost (¢/kWh)		Average weekend cost (¢/kWh)	
	Non-SSI	SSI	Non-SSI	SSI
June 1980	1.1	0.6	1.3	0.6
July 1980	1.5	0.8	1.5	0.7
August 1980	1.6	0.9	1.4	0.8
September 1980	1.3	0.7	1.2	0.7
October 1980	1.3	0.7	1.2	0.7
November 1980	1.7	0.8	1.7	0.8
December 1980	1.9	0.9	2.1	0.9
January 1981	2.4	1.1	2.5	1.1
February 1981	2.2	1.0	2.0	0.9
March 1981	1.8	0.9	1.7	0.9

monthly energy costs for SSI customers are approximately half those of non-SSI customers in the summer and off-season months but are less than half in the winter months. This suggests that when the costs are assessed for all the SSI customers together, they are considerably less than those for the non-SSI customers. The cost pattern for the typical weekend day is essentially the same as that for the typical weekday, indicating that SSI energy costs are about half those of non-SSI customers on the weekend.

The comparative analysis result that within-rate usage differences between SSI and non-SSI customers are smaller than the overall differences provides a guide for evaluating the within-rate cost implications. A costing analysis for within rate classes would show the same general pattern as the comparative results because the same hourly production costs would be used to calculate the differences within rate classes. No detailed cost estimates are provided because the relative relationship is already established.

Table 7-5 presents the marginal energy costs at the hour of monthly system peak for SSI and non-SSI customers. These costs are calculated by multiplying peak hour usage for each group by the system marginal energy cost for the last unit dispatched to meet load.

The marginal energy costs for the non-SSI customers are considerably larger than those for the SSI customers. Non-SSI marginal energy costs exceed those for SSI customers by slightly less than a 2 to 1 margin in the closest month, September, to almost a 3 to 1 margin in January. These large margins reflect the substantially lower consumption of SSI customers at the hour of monthly system peak.

The cost of serving SSI customers, measured in either marginal or average energy costs, are substantially less than those of serving non-SSI

TABLE 7-5. MARGINAL ENERGY COST[a] AT HOUR OF MONTHLY SYSTEM PEAK--NON-SSI AND SSI CUSTOMERS

Month/year	System marginal energy cost (¢/kWh)	Non-SSI customers Peak usage (kWh)	Non-SSI customers Marginal cost (¢/kWh)	SSI customers Peak usage (kWh)	SSI customers Marginal cost (¢/kWh)
June 1980	7.6	1.845	14.02	0.928	7.05
July 1980	8.5[b]	2.038	17.32	1.014	8.62
August 1980	8.5[b]	2.438	20.72	1.447	12.30
September 1980	8.5	1.572	13.36	0.986	8.38
October 1980	8.5	2.174	18.48	0.969	8.24
November 1980	8.5	3.159	26.85	1.221	10.38
December 1980	8.5	2.968	25.23	1.208	10.27
January 1981	8.5	3.460	29.40	1.320	11.22
February 1981	8.5	3.175	26.99	1.271	10.80
March 1981	8.5	2.401	20.41	1.042	8.86

[a]Production cost of the last unit dispatched in each month to meet load.

[b]Power purchases were required to meet load this month. The cost of the last unit dispatched must be at least equal to the cost of purchased power.

customers. This suggests that the SSI rate may be justified on the basis of a lower cost of serving these customers. Determination of a permanent rate for SSI customers requires careful consideration of its overall rate design implications by both Duke Power Company and the North Carolina Utilities Commission.

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Turvey, Ralph, and Dennis Anderson, Electricity Economics, Baltimore: Johns Hopkins University Press for the World Bank, 1977.

APPENDIX A

RELATIONSHIP OF THE SSI RATE TO LIFELINE RATES IN THE UNITED STATES

Source: W. H. Desvousges, D. H. Brown, M. P. McGivney, Lifeline Rates and Alternatives: A Program Survey, Cooperative Agreement No. DE-FC-01-79-RG-10255, June 1981.

APPENDIX A

RELATIONSHIP OF THE SSI RATE TO LIFELINE RATES IN THE UNITED STATES

The SSI rate in North Carolina is best viewed in the larger context of lifeline rates. The Public Utilities Regulatory Policies Act of 1978 required States to assess the feasibility of lifeline rates. These rates are derived from the premise that a certain amount of energy is required to sustain life, but, unfortunately, the term lifeline lacks a universal definition. The purpose of a lifeline rate is either to create lower-than-average rates for groups of electricity consumers or provide all residential customers a certain usage at rates lower than the cost of serving them.

Lifeline rate programs are established in two ways: (1) the program may be developed on a marginal cost basis, and (2) it may be designated on the basis that it subsidizes the energy consumption of certain users. The marginal cost justification is based on the economic efficiency criterion that the consumer's valuation of the incremental unit of a good should be equal to the additional (marginal) cost of producing that unit. Lifeline rates that provide a lower charge for the initial units of energy consumed are efficient if the lower rates reflect the marginal cost of energy production.

Lower rates on the initial units of consumption are based on the reasoning that users who consume small amounts of energy impose lower marginal costs than other users. This rationale, however, overlooks the fact that the time of use is as important as total use in determining costs. Small users may add significantly to costs if their consumption occurs at utility peak periods. Large users may add very little to costs if their consumption occurs at times of excess utility capacity. Regulators should consider both the amount of consumption and the time of consumption in determining if lifeline rates are cost-justified. Indeed, most state commissions have argued that lifeline rates should be implemented only if cost-justified. New York, for example, supports a 300-kWh lifeline block of electricity as a move toward marginal cost pricing. This project employs both use and time-of-use evaluation measures to determine if the SSI discount can be justified on a cost-of-service basis.

The second rationale in various states for lifeline rates is that utilities can subsidize certain individuals. These programs are generally identified as those lowering rates to groups based on income, family, and age characteristics. It is argued that assistance is needed by these individuals to purchse some basic level of energy. Rates are purposely set below marginal costs in these cases. The resulting transfers of income are best evaluated by the political process, but the use of lifeline rates to transfer income is questionable because of the costs involved. The actual amount of assistance is usually small yet high administration costs may be incurred. These transfers in many cases could be accomplished by existing government programs in a more cost-effective manner that would not affect the energy price signals to consumers.

Because of various identification problems, it is often difficult to determine if a state has a lifetime program. Some problems arise because the direction of the correlation between income and energy consumption is unknown. Depending on the direction of this correlation, a program designed for low-use customers may be classified as lifeline program. If low-income consumers use inefficient heating and cooling equipment and have poorly insulated homes and high-income consumers have more efficient equipment, better insulation, and spend a great deal of time away from home, then a negative correlation of income and usage exists. Programs aimed at low-use consumers will thus have a perverse effect on the existing income distribution because low-income households will be subsidizing consumption by high-income households.

Alternatively, as income increases, consumers may buy larger homes or more energy-intensive appliances, causing a positive correlation of electricity usage and income. If this situation exists, then low-use subsidies will be analogous to low-income subsidies. These programs, however, would still adversely affect those low-income families that do consume large amounts of energy.

The second problem in the identification of lifeline programs is the determination of the groups eligible for reduced rates. Eligibility requirements range from specific age and income limits to statewide programs for all residents. The State of California instituted the first statewide lifeline rate in 1975 for all residential customers. The program provided residents with reduced rates on a basic allowance of electricity and natural gas with increases for specific energy uses such as water heating, air conditioning, and space heating. In 1980, Michigan passed a bill requiring utilities to design lifeline rates for residents using less than 350 kWh per month of electricity. Montana requires each utility to establish a lifeline rate for residents who use under 15 thousand cubic feet (Mcf) per month of natural gas. Some individual utilities in Georgia, Washington, D.C., Minnesota, South Carolina, and Vermont offer lifeline rates to all residential customers.

Age and income requirements are usually specified in lifeline programs. Maine's demonstration project limited special rates to residents 62 years old with annual incomes of less than $5,000. Programs aimed at specific groups tend to conform with the basic income transfer premise of lifeline rates because household income is the limiting constraint in the purchase of a minimum amount of energy.

The amount of consumption subsidized also varies by state and season of the year. The breakoff points range from 150 kWh for Vermont to 1,000 kWh for South Carolina. The typical breakoff is usually between 350 and 650 kWh. For natural gas the lifeline breakoff point ranges from 26 therms per month for California to approximately 150 therms (15 Mcf) per month for Montana. Assistance actually received by residents under these programs is difficult to calculate. Subsidies vary with household characteristics and consumption and between seasons. Household savings range from almost zero to almost $9.00 per month for Maine.

Several states offer a fixed amount of assistance for all energy payments as a substitute for lower rates for certain types of energy. These payments in many cases tend to be larger than the true lifeline rate subsidies. Montana, Kentucky, New Jersey, Indiana, and Ohio offer payments of from $40 to $200 per heating season with the amount of assistance varying between seasons and with the type of fuels used. Payments are either credited to a household's utility bill or deducted from taxes. In Kentucky, however, individuals receive the assistance payment directly. Assistance is offered to specific residential groups; for instance, recipients must be receiving Supplemental Security Income checks in Indiana and New Jersey to receive the energy payments assistance. The most important difference between reduced lifeline rates and fixed payments is that fixed energy payments are usually subsidized by general tax revenue while lifeline rates are subsidized by other utility customers.

The West Virginia Public Service Commission in a May 1981 rate case provided a special rate to SSI recipients in the Appalachian Power Company territory on a trial basis. The PSC approved the rate because the SSI customers were easily identifiable and their small number would have a minimal effect on revenues. The PSC order stated that residential class customers will bear the costs of the SSI rate.

Because of the disagreement in interpreting the Public Utilities Regulatory Policies Act (PURPA) of 1978, considerable inconsistency exists in the implementation of lifeline rates. PURPA recommends to state commissions that rates be cost based but also requires states to consider lifeline rates. The only consistent interpretation of PURPA requires that lifeline rates be implemented only if they are cost-justified. This interpretation, however, is inconsistent with the lifeline premise of providing some necessary amount of energy at a low cost. The problem is compounded by court cases in several states that have questioned the constitutionality of reduced rates to a certain group of customers. These court cases have caused the termination of assistance programs in Colorado, Utah, and Idaho.

Lifeline rate issues will continue to be a difficult policy issue for both regulatory and legislative officials. The cross-currents produced by the conflicting goals of cost-based pricing and minimum energy needs at reasonable cost will only worsen as the cost of energy production rises. The difficulty of the issue is heightened by the lack of sound data on the cost justifications for lifeline rates and the confusion over the correlation between energy usage and income. This report provides empirical evidence in an attempt to shed some light on these facets of the lifeline controversy.

APPENDIX B

DATA HANDLING PROCEDURES AT DUKE POWER COMPANY

Libby

MOST COMMON PROBLEMS WITH FIELD TAPES
FOUND IN TRANSLATION PROCESS

1. Multiplier changed
2. Low Usage
3. Erratic Timing
4. Split Intervals
5. Recorder Failure
6. Switched Channels
7. Bad Tape
8. Bad Information on Cards
9. Light Source
10. Undetermined Outage
11. Blank Tape
12. Recorder not Tracking
13. Missing Data on Channel ______
14. PO/PU
15. Missing Data & Intervals

Load Research Operations
Rate Department
1-16-79

LOAD RESEARCH OPERATIONS' DEFINITIONS OF MOST COMMON PROBLEMS WITH FIELD TAPES FOUND IN TRANSLATION PROCESS

1. Multiplier Changed - This problem would occur when the bill meter, watthour meter, or recorder constants have been changed to something other than the constants reported on the original installation sheet.

2. Low Usage - Tapes having less than 100 Kwh usage are given special consideration. If the comparison of Pulse Meter to Billing Meter is close or the difference is not more than twice the largest multiplier then the tape is accepted, regardless of percentage. If the translation falls outside of these considerations, it is reported as missing data. The comparison on all reports will remain a rejected status 2 eventhough the operater will transfer the data to 1600 BPI tape.

3. Erratic Timing - Timing channel reflects the amount of tape travel in units of milli-seconds. Each 15 minute recorder would produce 15 minute intervals of approximately 30 milli-seconds. Each 30 minute recorder would produce 30 minute intervals of approximately 60 milli-seconds. If at the time of translation, the timing channel reflects intervals of extremely high or low values, then the problem would be flagged as erratic timing. This would be caused by the recorder motor changing speed. (KR possible codes: DE, RP, RR).

   Ex:

Normal 15 min. pattern		Erratic timing pattern	
2967		2967	
2943	1 hr.	609	1 hr.
2959		4078	
2980		2001	

4. Split Intervals - The timing length for 15 or 30 minute recorders is predetermined at approximately 30 milli-seconds and 60 milli-seconds, respectively. Split or broken intervals are the result of recorder malfunction. This can be determined by the timing channel values. (possible KR codes: DE, CI)

Ex A: Normal 15 min. pattern					Ex B: Split interval 15 min.				
1	2967	5	2979		1	2967	5	2979	
2	2943	6	2947	2 hrs.	2	2943	6	2620	2 hrs.
3	2959	7	2952		3	2629	7	327	
4	2980	8	2952		4	330	8	2952	

As you can see in Ex. B, the values of interval #3 & #4 should be added together to reach a normal value of 2959. Intervals #6 & #7 should also be combined to give a value of 2947. Split intervals differ from erratic timing in that they can be combined for a valid data value. Erratic timing has no pattern and cannot be corrected.

5. Recorder Failure - The tape for a given period was short on data and intervals expected. The tape was verified and found good. No outages occurred and power was connected. Usually, the data pulses are good until a certain point (which may be several hours or days short of expected time) after that point, there are no intervals or data. This shows the same affect that would result if all power were removed at once. (possible KR codes: DE, RP, CI)

6. Switched Channels - Data channels on 4 track recorders that are wired incorrectly. This indicates data which should actually be on channel C is recorded on B and vice versa.

7. Bad Tape - The tape has been verified and could not read expected data. At this point, the tape is discarded. No trouble report will be sent.

8. Bad Information on Cards - Part or all of the start and stop dates, times, and readings were incorrect or omitted.

9. Light Source - Light source is suspected when a tape for a customer that usually has a regular pattern shows a splotchy pattern and is missing a large amount of expected data. (possible KR codes: DE, RP, RR)

10. Undetermined Outage - At the time the tape is changed, outage is checked on the ID card or a note is made on the back that power was off for x number hours with no dates given. Data would be purged.

11. Blank Tape - Tape was translated but found no data pulses or timing intervals.

12. Recorder not Tracking - When readings from both a pulse generator meter and a watthour meter are written on the ID card, they are expected to show a similar total. If this is not the case and one total is far greater or smaller than the other, and the translation shows the same comparison, then we report a tracking problem.

13. Missing Data on Channel - Missing data indicates the translation found fewer pulses than expected. The expected pulse count was determined by the start and stop meter readings and the meter constants on the ID card.

14. PO/PU (Post-Purge) - PO/PU indicates the data on that particular tape was not usable but that the stop date, time, and readings were retained for use on the next tape.

15. Missing Data & Intervals - Fewer data pulses and intervals found in translation than expected from information on ID card.

ADVANCED WLT-40
OPERATIONS MANUAL

DUKE POWER COMPANY

Charlotte, North Carolina

Westinghouse Electric Corporation • Meter & LVIT Division • Raleigh, N. C.

Code	Action
DE	Delete Intervals.
AD	Add intervals. The start and stop times may not cover more than 38 intervals. The system will determine how many interval values are required to cover the start thru stop time, and request them, eight at a time, for each channel: CH Z: XX TO YY — where Z is A, B, or C; XX and YY are interval number offsets from the correction start time. If an invalid interval value is entered, INTERVAL XX INVALID is typed and the values beginning, with the incorrect one, must be re-entered. In all cases, the system will specify the interval numbers it expects. A value entry of "GO" will imply that the last value entered is to be repeated thru the correction stop time. If it is entered for the first correction interval value, a pulse count of zero is assumed for the entire correction period.
RP	Replace intervals. Number of intervals limit and interval value entry is the same as for the AD type. In addition, a value entry of "NC" will tell the system that No Change is desired for the specified interval.
RA	Repetitive Add intervals. One value only is requested for each channel, and that one value is inserted for indicated interval. No limit is placed on the correction time span.
RR	Repetitive Replace intervals. One value or "NC", indicating No Change, is requested for each channel and that one value replaces the value for each indicated interval. No limit is placed on the correction time span.
CI	Combine Intervals. All intervals between the start and stop times will be combined, and the subsequent intervals skewed.

APPENDIX C

SURVEY INSTRUMENTS FOR SSI AND RESIDENTIAL LOAD RESEARCH CUSTOMERS

SUPPLEMENTARY SECURITY INCOME DEMOGRAPHIC SURVEY

LOAD RESEARCH REFERENCE NUMBER

1. Group No. ____
2. Strata No. ___
3. Ident. No. ____________
4. Soc. Sec. No. ___ __ ____

5. TYPE OF RESIDENTIAL STRUCTURE
   - ☐ House
   - ☐ Apartment
   - ☐ Mobile Home
   - ☐ Condominium

6. SIZE OF STRUCTURE ____

7. NUMBER OF PERSONS IN HOUSEHOLD __

8. NUMBER OF PERSONS IN HOUSEHOLD RECEIVING SSI PAYMENTS __

9. TYPE OF HEATING SYSTEM
   - ☐ Electric Room by Room System
   - ☐ Electric Furnace
   - ☐ Heat Pump
   - ☐ Gas, Oil or Coal Central System
   - ☐ Gas, Oil or Coal Space Heater
   - ☐ Other ____________________

10. ARE ANY OF THE FOLLOWING NORMALLY USED TO HELP HEAT THE STRUCTURE?
    - ☐ Solar
    - ☐ Portable Electric Heaters
    - ☐ Fireplace
    - ☐ Wood Stove
    - ☐ Other ____________________

11. CENTRAL ELECTRIC AIR CONDITIONING
    - ☐ Yes

12. "WINDOW TYPE" AIR CONDITIONERS
    - ☐ Yes

13. WATER HEATING
    - ☐ Electric
    - ☐ Gas
    - ☐ Oil
    - ☐ Solar
    - ☐ None

14. INDICATE ANY OF THE FOLLOWING MAJOR APPLIANCES IN THE STRUCTURE
    - ☐ Electric Range
    - ☐ Frost-Free Refrigerator
    - ☐ Non Frost-Free Refrigerator
    - ☐ Frost-Free Freezer
    - ☐ Non Frost-Free Freezer
    - ☐ Clothes Washer
    - ☐ Electric Clothes Dryer
    - ☐ Gas Clothes Dryer
    - ☐ Dishwasher
    - ☐ Waste Disposal
    - ☐ Trash Compactor
    - ☐ Microwave Oven

Notes: ____________________

____

____

____

Res. Rep. ____________________

Date ____________________

I/A

SSI SUPPLEMENTAL SURVEY

Sample

CALDWELL, ODESSA
R14 MOORES CHPL RD
CHARLOTTE, NC 28208
-01261402351
03

EDP FILE REFERENCE

3. Ident. No. 0 1 0 2 3 5 0 3 1 1 1 1

This questionnaire should be completed for each SSI household currently being monitored for load research purposes. A personal interview is not recommended. Estimates should be obtained by simply driving by the residence. If the address is an apartment for which the owner can be easily identified, a phone call should be placed to the owner to obtain the rent for 1, 2, and 3 bedroom living units.

All questionnaires should be completed and returned to Ben Christenbury by November 1, 1980.

15. Year house built

- ___ 1930 or before
- ___ 1931 to 1940
- ___ 1941 to 1950
- ___ 1951 to 1960
- ___ 1961 to 1970
- ___ 1971 to 1980

16. Present market value

- ___ $10,000 or below
- ___ $10,001 to $20,000
- ___ $20,001 to $30,000
- ___ $30,001 to $40,000
- ___ $40,001 to $50,000
- ___ $50,001 to $60,000
- ___ $60,001 to $70,000
- ___ $70,001 to $80,000
- ___ $80,001 to $90,000
- ___ $90,001 to $100,000
- ___ $100,001 or above

If the housing unit is a duplex, please indicate an estimate for one side or one housing unit.

17. If the housing unit is an apartment, please determine monthly rental from owner or manager, if possible (not tenant).

1 Bedroom ______________

2 Bedroom ______________

3 Bedroom ______________

Other ______________

Surveyed by ______________

Date ______________

Comment ______________

____

9/5/80

RESIDENTIAL MARKET RESEARCH SURVEY

Load Research Reference Number

1. Group No. |_|_|_|_|
2. Strata No. |_|_|
3. Ident. No. |_|_|_|_|_|_|_|_|_|_|_|_|

(Circle Number For The Proper Answer Or "Fill-in" All Spaces)

A. TYPE STRUCTURE
1. House
2. Apartment
3. Mobile Home
4. Condominium
5. Summer Home

B. YEAR BUILT 19__

C. STYLE OF STRUCTURE
1. One Level
2. Two Level
3. Tri-Level (or more)
4. Double Wide

D. SIZE OF STRUCTURE
____ Sq. ft.

E. IS THIS AN EES STRUCTURE?
1. Yes
2. No

F. MEMBERS OF HOUSEHOLD
1. Under 6 years old ____
2. From 6 through 18 years ____
3. From 19 through 65 years ____
4. Over 65 years old ____

G. HOW MANY MEMBERS SHOWN IN QUESTION F ARE LIVING AWAY FROM HOME AT COLLEGE OR OTHER TYPES OF SCHOOLS? ____

H. DO YOU LIVE
1. Inside the city limits of a town or city
2. Within a residential sub-division but outside the city limits
3. In a rural area
4. On a farm

I. PRIMARY HEATING FUEL
1. Electric
2. Gas
3. LP Gas
4. Oil
5. Other
6. None

J. TYPE OF PRIMARY HEATING SYSTEM
1. Room-by-Room Electric
2. Electric Furnace
3. Heat Pump
4. Fossil Central System
5. Fossil Space Heater
6. None

K. ARE ANY OF THE FOLLOWING NORMALLY USED TO HELP HEAT YOUR HOME?
1. Solar
2. Portable Electric Heaters
3. Fireplace
4. Wood Stove
5. Range
6. Other ____________
7. None

L. AIR CONDITIONING
1. Central Electric
2. Central Gas
3. Window Units
4. None

M. YEAR INSTALLED 19__
(Latest year if window units)

N. TOTAL NUMBER IF WINDOW UNITS IN L ______

O. IS THERE A "HEAT RECLAIM" DEVICE ON THE CENTRAL AIR CONDITIONING?
1. Yes

P. WATER HEATING
1. Electric
2. Gas
3. Other
4. None

Q. SOLAR WATER HEATING
1. Yes
2. No

R. ELECTRIC WATER HEATER SIZE
1. 80 gal.
2. 66 gal.
3. 50 gal.
4. 40 gal.
5. 30 gal.
6. Smaller

S. WHAT IS THE LARGEST SIZE ELECTRIC WATER HEATER THAT CAN BE INSTALLED AT THE PRESENT LOCATION?
1. 80 gal. (64"H x 26"W)
2. 66 gal. (64"H x 25"W)
3. 50 gal. (60"H x 22"W)
4. 40 gal. (48"H x 22"W)
5. Tank size cannot be increased

T. ELECTRIC WATER HEATER LOCATIO
1. Basement
2. Crawl Space
3. Storage Area
4. Living Area
5. Attic
6. Other

U. MICROWAVE OVEN
1. Yes
2. No

V. PERCENT OF MEALS PREPARED BY MICROWAVE OVEN

1. 10% or less
2. 11% - 20%
3. 21% - 30%
4. 31% - 40%
5. over 41%

W. TOTAL MEALS PER WEEK ___

X. RANGE

1. Electric
2. Gas
3. Other
4. None

Y. PRIMARY REFRIGERATION

1. Side by Side
2. Other Types of Frost Free
3. Non-Frost Free
4. None

Z. SECONDARY REFRIGERATION

1. Side by Side
2. Other Types of Frost Free
3. Non-Frost Free
4. None

AA. PRIMARY FREEZER

1. Frost Free
2. Other
3. None

BB. SECONDARY FREEZER

1. Frost Free
2. Other
3. None

CC. CLOTHES WASHER

1. Yes
2. No

DD. DISHWASHER

1. Yes
2. No

EE. DISPOSAL

1. Yes
2. No

FF. CLOTHES DRYER

1. Electric
2. Gas
3. None

GG. TRASH COMPACTOR I/A

1. Yes
2. No

HH. TELEVISIONS

__1__ Total Number

II. HAVE YOU ADDED HOME INSULATION WITHIN THE LAST 12 MONTHS?

1. Ceiling
2. Sidewall
3. Floor
4. Storm Windows
5. None

JJ. ARE YOU AWARE OF DUKE POWER'S ENERGY EFFICIENT APPLIANCE PROGRAM?

1. Yes
2. No

KK. APPLIANCES PURCHASED IN THE LAST 12 MONTHS

1. Refrigerator
2. Electric Water Heater
3. Dishwasher
4. Room Air Conditioner
5. None of the above

LL. WERE THEY ENERGY EFFICIENT APPLIANCES?

1. Refrigerator
2. Electric Water Heater
3. Dishwasher
4. Room Air Conditioner
5. No

MM. WHAT PERCENT OF YOUR HOME DO YOU HEAT?

1. 100%
2. 80%
3. 60%
4. 50%
5. Less than 50%

NN. WHAT IS YOUR NORMAL THERMOS' SETTING FOR HEATING?

___ °F

OO. WHAT IS YOUR NORMAL THERMOS' SETTING FOR HEATING AT NIGHT?

___ °F

PP. WHAT TIME IS THE HEATING "SET BACK"?

(Military time) ___

QQ. WHAT TIME IS IT "SET UP"?

(Military time) ___

RR. DO YOU LET YOUR AIR CONDITIONI OPERATE DURING THE DAY, IF YOU ARE NOT AT HOME?

1. Yes
2. No

SS. WHAT IS THE NORMAL THERMOSTA SETTING FOR YOUR AIR CONDITIONI

___ °F

TT. WHAT PERCENT OF THE HOME DO YOU AIR CONDITION?

1. 100%
2. 75%
3. 50%
4. 25%
5. Less than 25%

UU. COULD WE INSTALL A RECORDING METER ON YOUR HOME IF REQUIRE BY REGULATORY BODIES?

1. Yes
2. No

VV. ESTIMATE THE FOLLOWING

1. For Rental Living Unit, the Monthly Rent $___
2. For Others, Present Market Value $___

HEAT GAIN AND HEAT LOSS FOR 1979 RESIDENTIAL MARKET RESEARCH SURVEY

9. NO. PEOPLE [illegible]

10. TEMP. DIFF. HTG. [illegible] 11. ROOF L T (Lt. or Dk.) 12 DUCT INS. 0 Inch (es)

13. DUCT LOCATION [illegible]
A - Attic C - Crawl Space
N - None

FOR FIELD USE ONLY

Table for Calculating Shaded & Unshaded Glass Areas				
1. Direction Window Faces				
2. Total Window Area Sq. Ft.				
3. Width of Window, Ft.				
4. Shaded Area Per Foot of Overhang - Table B - 1, Sq. Ft.				
5. Width of Overhang, Ft.				
6. Total Area of Shaded Glass, Sq. Ft. (Line 4) X (Line 5)				
7. Total Area of Unshaded Glass, Sq. Ft. (Line 2) — (Line 6)				

	TYPE OF EXPOSURE		Const. No.	HTM Htg	HTM Clg	Area or Length
20	Gross Walls	a				1 [illegible]
21	Windows and Glass (Htg)	a	13 A			0 0 18
		b				
		c				
22	Windows and Glass (Clg)	a	North		.	
		b	North		.	
		c	E&W or NE&NW		.	
		d	E&W or NE&NW		[illegible] 5 . 0	[illegible]
		e	South or SE&SW		3 0 . 0	[illegible]
		f	South or SE&SW		.	
23	Doors	a	1 9 C		.	[illegible]
		b			.	
		c			.	
24	Net Exposed Walls and Partitions	a	1 0 A		.	[illegible]
		b			.	
		c			.	
		d			.	
25	Ceilings	a	1 [illegible] A		.	1 0 [illegible]
		b			.	
26	Floors	a	1 7 B		.	1 0 [illegible]
		b			.	

Res. Rep:

Date:

APPENDIX D

STATISTICAL ESTIMATION AND TESTING METHODOLOGY

APPENDIX D

STATISTICAL ESTIMATION AND TESTING METHODOLOGY

The design of the Duke Power Company SSI Rate Study involves the use of two stratified random samples. The first sample was selected from the population of North Carolina residential customers not on the SSI rate in August 1979. Members of the second sample were drawn from the population of North Carolina residential customers served by the SSI rate at that time.* Because of the relatively simple designs, the estimation methodology is straightforward if stratum sizes are assumed known. This assumption is made throughout.

Notation and Parameters of Interest

The first population of interest, consisting of sample-eligible, non-SSI, North Carolina residential customers in the Duke service area, is denoted by I=1; and the second population, by I=2. Define the following:

$N(I,h)$ = the number of customers in the h^{th} stratum of the I^{th} population, $h = 1, 2, \ldots, H_I$;

$$N(I) = \sum_{h=1}^{H_I} N(I,h) = \text{number of customers in the } I^{th} \text{ population;}$$

$n(I,h)$ = the number of sample customers selected from the h^{th} stratum of the I^{th} population;

$r_Y(I,h)$ = the number of sample customers in the h^{th} stratum of the I^{th} population who provide "valid" data on a given response variable, Y.

---

* Some exclusions prevented some of the residential customers from being eligible for either of these samples.

Let Y and Z represent two arbitrary response variables. For instance, Z might represent "kWh consumed during the hour of system peak load of a particular month", and Y might represent "average hourly kWh consumed during the particular month." Let Y(I,h,i) and Z(I,h,i) denote the values of such variables for the i^{th} customer of the h^{th} stratum in the I^{th} population. The parameters of interest are of two types:

$$\text{Averages:} \quad \overline{Y}(I) = \sum_{h=1}^{H_I} \sum_{i=1}^{N(I,h)} Y(I,h,i) \;/\; N(I)$$

$$\text{Load Factors:} \quad \frac{\overline{Y}(I)}{\overline{Z}(I)} = \frac{\sum_{h=1}^{H_I} \sum_{i=1}^{N(I,h)} Y(I,h,i) \;/\; N(I)}{\sum_{h=1}^{H_I} \sum_{i=1}^{N(I,h)} Z(I,h,i) \;/\; N(I)} .$$

Estimation of these two types of population parameters is described in the following sections. To facilitate that discussion, it is convenient to define the following for each sample member:

$X_Y(I,h,i)$ = 1, if the i^{th} sample member in the h^{th} stratum of population I provides valid data on the arbitrary response variable Y, and

= 0, otherwise.

Note that

$$r_Y(I,h) = \sum_{i=1}^{n(I,h)} X_Y(I,h,i).$$

Estimation of Population Averages

Estimates of $\overline{Y}(I)$ are obtained as weighted averages of the sample stratum means:

$$\hat{\overline{Y}}(I) = \sum_{h=1}^{H_I} \frac{N(I,h)}{N(I)} \hat{\overline{Y}}(I,h)$$

where

$$\hat{\bar{Y}}(I,h) = \sum_{i=1}^{n(I,h)} X_Y(I,h,i)\ Y(I,h,i) \ / \ r_Y(I,h).$$

It should be noted that this estimate (and subsequent estimates) involve an implicit imputation when $r_Y(I,h) < n(I,h)$, i.e., when some sample customers fail to provide valid data on the particular response variable.

It is assumed that $r_Y(I,h) \geq 2$ for all I and h*; hence, the standard error of the estimated average $\hat{\bar{Y}}(I)$ is obtained by taking the square root of

$$\widehat{\mathrm{Var}}\left[\hat{\bar{Y}}(I)\right] = \sum_{h=1}^{H_I} \left[\frac{N(I,h)}{N(I)}\right]^2 \ s_Y^2(I,h)\ f_Y(I,h) \ / \ r_Y(I,h),$$

where $f_Y(I,h) = 1 - r_Y(I,h) \ / \ N(I,h)$ is the finite population correction factor for the h^{th} stratum of population I, and $s_Y^2(I,h)$ is the variance of Y among the $r_Y(I,h)$ respondents in the h^{th} stratum of the I^{th} population, i.e.,

$$s_Y^2(I,h) = \sum_{i=1}^{n(I,h)} X_Y(I,h,i)\left[Y(I,h,i) - \hat{\bar{Y}}(I,h)\right]^2/\left[r_Y(I,h)-1\right].$$

Estimation of Population Load Factors

Assume that $X_Y(I,h,i) = X_Z(I,h,i)$; that is, assume that those sample customers providing valid data on Y also provide valid data on another response variable Z.** With appropriate definitions of Y and Z, and assuming a known fixed time for which the load factor is to be

---

* When this fails to hold, customers in the affected strata are grouped with those in an adjacent stratum. Some bias in the estimates, as well as decreased precision, can be expected to result from collapsing strata in this fashion.

** Otherwise, the data file is restricted to such customers and the definition of $X_Y(I,h,i)$ is modified accordingly.

determined (e.g., the hour of system peak), the estimate of a load factor for the I^{th} population, R(I), has the form

$$\hat{R}(I) = \frac{\hat{\bar{Y}}(I)}{\hat{\bar{Z}}(I)} ,$$

where both the numerator and denominator are estimated in the manner of the previous section.

The estimated variance of $\hat{R}(I)$ is approximated as

$$\widehat{Var}\ [\hat{R}(I)] = \frac{1}{\hat{\bar{Z}}(I)^2}\left\{\widehat{Var}\ [\hat{\bar{Y}}(I)] + [\hat{R}(I)]^2\ \widehat{Var}[\hat{\bar{Z}}(I)] - 2\hat{R}(I)\ \widehat{Cov}[\hat{\bar{Y}}(I),\hat{\bar{Z}}(I)]\right\},$$

where

$$\widehat{Cov}[\hat{\bar{Y}}(I),\hat{\bar{Z}}(I)] = \sum_{h=1}^{H_I} \left[\frac{N(I,h)}{N(I)}\right]^2 \frac{f_Y(I,h)}{r_Y(I,h)}\ s_{YZ}(I,h)$$

and

$$s_{YZ}(I,h) = \sum_{i=1}^{n(I,h)} X_Y(I,h,i)\ [Y(I,h,i) - \hat{\bar{Y}}(I,h)]\ [Z(I,h,i)-\hat{\bar{Z}}(I,h)]/[r_Y(I,h)-1].$$

Estimation and Comparison of Population Differences

Differences in the non-SSI and SSI population parameters are of two types:

1. Differences in population averages: $\bar{Y}(1) - \bar{Y}(2)$, and
2. Differences in population load factors: R(1) - R(2).

Such differences are estimated, respectively, as $\hat{\bar{Y}}(1) - \hat{\bar{Y}}(2)$ and as $\hat{R}(1) - \hat{R}(2)$. Under the assumption that these estimates are approximately normally distributed, approximate tests of significance can be performed to determine if differences exist in the population averages or load factors. In the first case, (i.e., comparison of population averages), the form of the test statistic is

$$T = \frac{\hat{\bar{Y}}(1) - \hat{\bar{Y}}(2)}{\sqrt{\widehat{Var}[\hat{\bar{Y}}(1)] + \widehat{Var}[\hat{\bar{Y}}(2)]}} .$$

Statistically significant differences (at the α level) are determined when this T value exceeds the $(1-\alpha/2) \times 100$ percentage point of the t distribution having degrees of freedom equal to

$$\sum_{I=1}^{2} \sum_{h=1}^{H_I} [r_Y(I,h) - 1].$$

The test statistic for comparing population load factors is of identical form, with $\hat{R}(I)$ replacing $\hat{\bar{Y}}(I)$ in the formula.

Estimation of Effects of Various Penetration Levels of SSI Customers

Let P, $0 \leq P \leq 1$, represent the proportion of Duke's North Carolina residential customers not on the SSI rate at some point in time. The electricity consumption during a particular time frame for the residential class as a whole can therefore be represented by

$$\bar{Y}_p = P\bar{Y}(1) + Q\bar{Y}(2),$$

where Q = 1-P and where $\bar{Y}(I)$ is the average consumption during the particular time frame for the I^{th} population. An estimate of $\bar{Y}_p$ is given by

$$\hat{\bar{Y}}_p = P\hat{\bar{Y}}(1) + Q\hat{\bar{Y}}(2).$$

Under the assumption of no population growth, the assumption that "new" SSI customers exhibit usage patterns like those of current (i.e., at the time of sampling) SSI customers, and the assumption that the remaining non-SSI customers exhibit usage patterns like those of current non-SSI customers, such estimates provide projected population estimates for the Duke North Carolina residential class as a whole (with the exception of those customers ineligible for either sample). Assuming that P is a known constant, the variance of $\hat{\bar{Y}}_p$ is estimated as

$$\widehat{\mathrm{Var}}(\hat{\bar{Y}}_p) = P^2\ \widehat{\mathrm{Var}}[\hat{\bar{Y}}(1)] + Q^2\ \widehat{\mathrm{Var}}[\hat{\bar{Y}}(2)].$$

Under the same assumptions, projected load factors, R_p, for the residential class can also be estimated. These estimates take the form

$$\hat{R}_p = \hat{\bar{Y}}_p \ / \ \hat{\bar{Z}}_p,$$

where the time frame for the numerator variable is chosen to be an average hour over a day (or month) and the time frame for the denominator variable is chosen as some specific hour during the day (or month). An approximate variance of the estimated load factor is estimated as

$$\widehat{\mathrm{Var}}(\hat{R}_p) = \frac{1}{\hat{\bar{Z}}_p^2} \left[\widehat{\mathrm{Var}}(\hat{\bar{Y}}_p) + \hat{R}_p^2\ \widehat{\mathrm{Var}}(\hat{\bar{Z}}_p) - 2\hat{R}_p\ \widehat{\mathrm{Cov}}(\hat{\bar{Y}}_p,\hat{\bar{Z}}_p)\right]$$

where

$$\widehat{\mathrm{Cov}}(\hat{\bar{Y}}_p,\hat{\bar{Z}}_p) = P^2\ \widehat{\mathrm{Cov}}[\hat{\bar{Y}}(1),\hat{\bar{Z}}(1)] + Q^2\ \widehat{\mathrm{Cov}}[\hat{\bar{Y}}(2),\hat{\bar{Z}}(2)].$$

APPENDIX E

GENERAL DESCRIPTION OF THE HYDRO MODEL

APPENDIX E

GENERAL DESCRIPTION OF THE HYDRO MODEL

HYDRO is a FORTRAN implementation of a series of models which simulate the dispatch of all forms of hydroelectric generating capacity on a month-by-month basis. Inputs to the model are of two forms:

1. Information (in GLiMPS format) which is used to construct unit fuel costs of power from non-hydroelectric generating capacity.

2. The system load curve (time-sequential) for the utility for an arbitrary number of months, in EEI format.

Output of the model is an EEI format load curve (time-sequential) for the same months' input, which has been revised to include the effects of the dispatch of the following forms of hydroelectric generating capacity.

1. Run-of-the-river

2. Conventional (behind-the-dam) storage

3. Pumped storage

It should be noted that in its present form, HYDRO is applicable only to Duke Power Company, and strictly applicable only to months in the period 1/1/80 through 12/3/95. Descriptions of hydroelectric facilities are internal to the model, i.e., embedded in the FORTRAN code. Generalization of the model can be obtained by revising the code to accept these data from external sources.

For each month, the system load curve is read into the program, and average hourly run-of-the-river power is removed.

Next, conventional storage hydro is dispatched, based on the total energy available from this source in a given month. The load curve for all hours in which demand exceeds a particle level (Y^*) is reduced to that level, subject to the constraint imposed by the maximum rate at which energy can be delivered. For Duke Power this rate is taken to be 812 MW.

Y^* is determined by the model as a function of the total energy in the month and the load duration curve for the month, shown in Figure E-1.

Finally, the energy to be shifted from peak to base by pumped hydro storage is determined and this capacity is dispatched.

This is the most complex section of the model. Consider Figure E-2. The curve B represents the gross benefit to the utility from displacing high cost generating capacity from peak hours. Curve C represents the gross cost of providing that power. Thus, the net profit to the utility is given by the (vertical) distance between these two curves. Economic theory suggests that this profit will be at a maximum at the point where the marginal benefit is equal to marginal cost (E^*). If the cost and benefit curves can be represented by equations, finding the optimum is easy.

However, the available data represent the curves as piece-wise linear approximations, so that the value of E^* can only be approximated in the normal case. The method used is as follows:

1. The highest-cost plant being used to meet demand is found.
2. The lowest-cost plant having unused capacity in the base period is found.
3. If the ratio of low-cost to high-cost of the plants (correcting for energy efficiency of the pumping process) is less than one, the current estimates of E^* lie to the left of E^* in Figure E-2. A better solution is possible. Two estimates of Y^* are found, associated with the high-cost and low-cost plants, respectively. From these values the amounts of energy (E^*) that can be shifted are found, and another plant is considered on the peak or base periods, whichever is smaller.

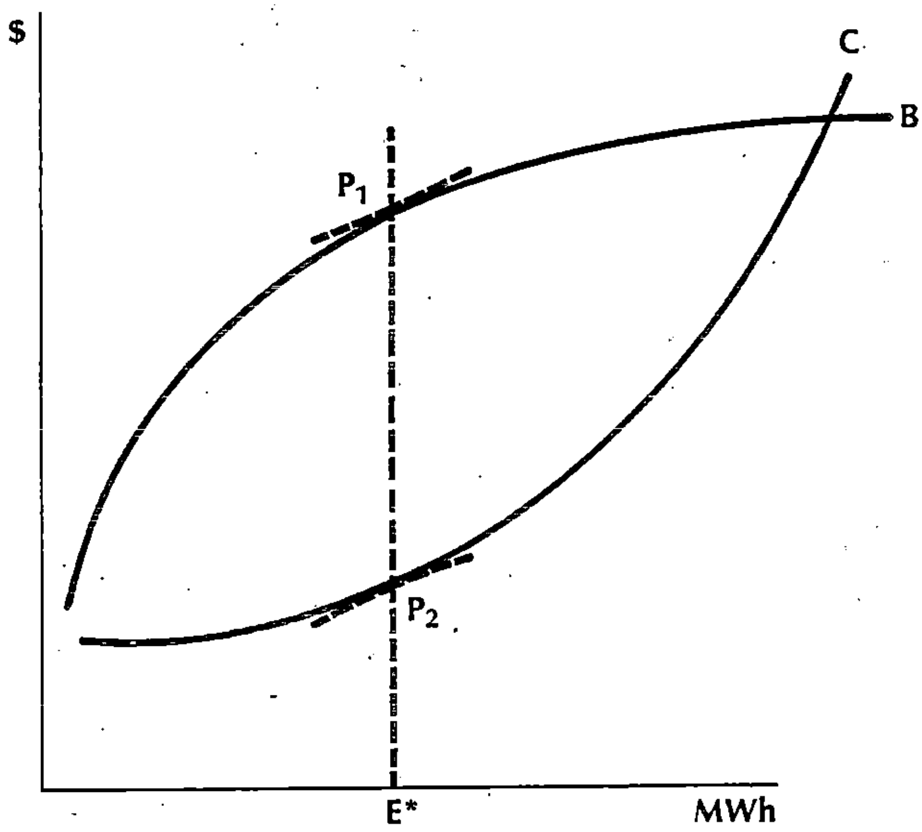

Figure E-1. Optimum energy supplied from pumped storage and associated pricing points.

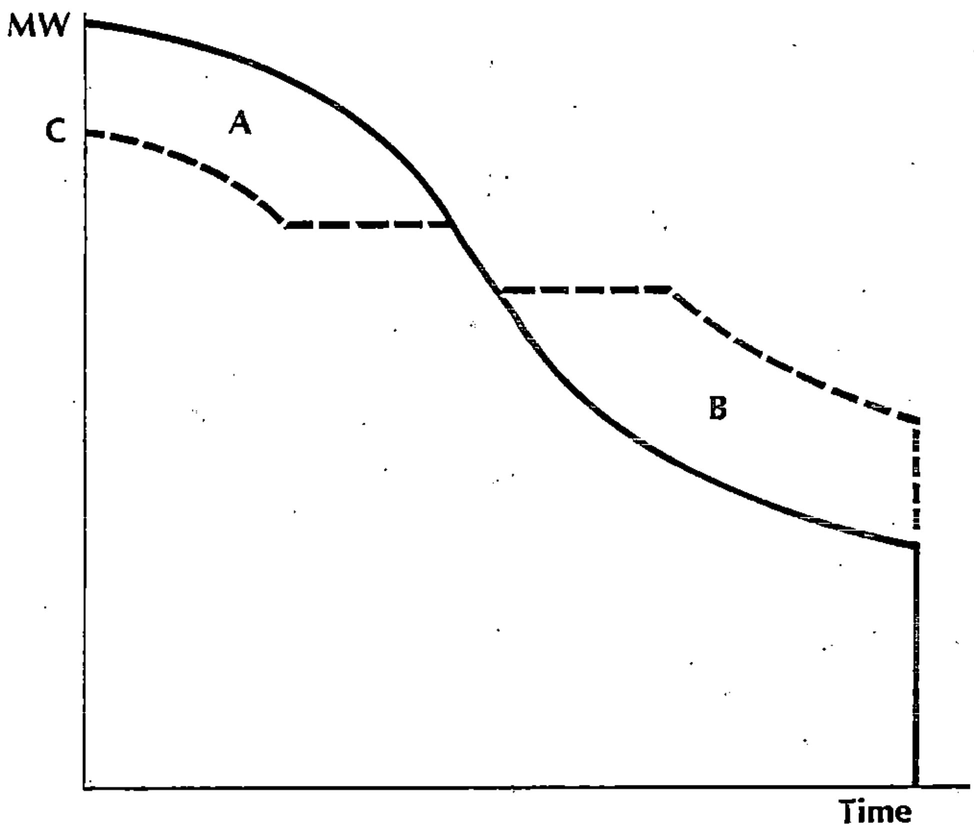

Figure E-2. Energy shifting with pumped storage subject to capacity and energy constraints.

4. If the ratio of low-cost to high-cost is greater than one, the current estimates of E^* are economically suboptimal, i.e., they lie to the right of the best value of E^* in Figure E-2.

   In this case, the previous solution is taken to be the best approximation of Y^*. The smaller amount of energy in the peak or base is the binding constraint, and the value of Y^* at the other end of the load duration curve is adjusted until its associated E^* is equal to the smaller amount.

5. The load curve for the month is then revised to the levels $Y\overset{*}{P}$ and $\overset{*}{Y}B$, constrained by the maximum charge and discharge rate of the system. This value is 610 representing Jocassee, and rises to 1610 MW by April 1991 as the Bad River facilities become available.

No check is made of possible capacity constraints of pumped hydro in the model, but our examination of the data suggests that no such constraint is binding.

Research Triangle Institute
Post Office Box 12194 Research Triangle Park NC 27709

PUBLIC STAFF
Floyd Exhibit 3
Page 1 of 2

List of Web Links for Programs in Other States Related to Low-Income Electric Rates and Assistance

1. Office of Legislative Research – "Utility Rate Discounts for Low-Income Customers in Other States, February 2018
https://www.cga.ct.gov/2018/rpt/pdf/2018-R-0051.pdf

2. ASPE – "Approached to Low-Income Energy Assistance Funding in Selected States," April 2014
https://aspe.hhs.gov/system/files/pdf/180296/rb_LIHEAP.pdf

3. Choose Energy – Compilation of Resources in Various States
https://www.chooseenergy.com/blog/energy-tips/summer-energy-assistance-programs/

4. National Grid Rhode Island - Rate discount for Eligible Low-Income Customers on Food Stamps, LiHEAP, or receiving SSI.
https://www.nationalgridus.com/RI-Home/Bill-Help/Discount-Rates

5. SMUD Low-Income Assistance and Non-Profit Discount
https://www.smud.org/en/Rate-Information/Low-income-and-nonprofits

6. Lite-Up Texas – Texas program that provided rate discounts to eligible low-income customers. Program was terminated in August 2017.
https://www.puc.texas.gov/consumer/lowincome/assistance.aspx

7. PECO – Customer Assistance Program provides monthly credits to eligible low-income customers.
https://www.peco.com/MyAccount/CustomerSupport/Pages/CAPRate.aspx
https://www.peco.com/MyAccount/CustomerSupport/Pages/AssistancePrograms.aspx

8. Pennsylvania Public Utility Commission – Summary of Energy Assistance Programs
http://www.puc.state.pa.us/consumer_info/electricity/energy_assistance_programs.aspx

9. Salt River Project – Flat discount of $23/month for eligible customers.
https://www.srpnet.com/prices/economy.aspx
https://www.srpnet.com/community/liprograms.aspx

10. ConEdison – Discount program for low-income customers who already have qualified for specific governmental assistance programs. https://www.coned.com/en/accounts-billing/payment-plans-assistance/help-paying-your-bill

11. City of Seattle – Rate Discount program for income-qualified customers. https://www.seattle.gov/light/assistance/

12. New Hampshire Public Utilities Commission - Electric Assistance Program provides discounts to low-income eligible customers https://www.puc.nh.gov/consumer/electricassistanceprogram.htm

13. Georgia Service Commission – Senior Citizen discount of up to $24 per month on electric bill for qualifying customers. https://psc.ga.gov/about-the-psc/consumer-corner/consumer-advisories/senior-citizens-discounts/

14. California Alternative Rates for Energy – Bill discount program. https://www.cpuc.ca.gov/General.aspx?id=976

I/A

Public Staff
Floyd Exhibit 4

Docket No. E-2, Sub 1219

Electric Utility Residential Customer Charges Minimum Bills

Jim Lazar
Regulatory Assistance Project
November 2014

I/A

Energy solutions
for a changing world

Electric Utility Residential Customer Charges and Minimum Bills:

Alternative Approaches for Recovering Basic Distribution Costs

By Jim Lazar[1]

Electric utilities have certain costs that do not vary with the usage of electricity. It is generally accepted that these include the costs of metering, billing, and payment processing. These costs are most often recovered through what is variously called a "customer charge" or a "service charge" or a "basic charge." In the United Kingdom, this is known as a "standing charge."

Regardless of the title, it is a charge (usually less than $10/month for residential service) that is levied each month regardless of electricity usage, with additional charges applying for each kilowatt-hour of electricity consumed. For most utilities in the US, the customer charge covers the cost of billing and collection, and perhaps other customer-specific costs like meter reading, but not the costs of distribution facilities like poles, conductors, or transformers.

Nearly all electric utilities worldwide bundle the cost of distribution service, as well as the power supply cost, into a usage charge, calculated as a price per kilowatt-hour. This is consistent with how competitive firms price their products, whether it is gasoline, groceries, or hotel rooms: the price per unit recovers all of the costs involved in producing, transporting, and retailing of goods and services.

Some rate analysts argue that a portion of the distribution system – poles, wires, and transformers – constitute a fixed cost that does not vary with sales and should be included in the fixed customer charge. Some recent proposals from electric utilities reflect this view. This is controversial.

Many state regulatory authorities rejected this approach when they held hearings and made determinations under the Public Utility Regulatory Policies Act of 1978.[2] The Washington Utilities and Transportation Commission, for example, explicitly rejected the concept that distribution costs were customer-related in nature:

> *In this case, the only directive the Commission will give regarding future cost of service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum sized system is not. The parties should not use the minimum system approach in future studies.*[3]

However, as sales have flattened or declined in recent years, and as more customers install on-site generating resources but remain dependent on grid services for some service, the concept of recovering distribution network costs in fixed charges has experienced resurgence.

Utility sales volumes in some regions have stagnated or declined as appliances, homes, equipment and systems become more efficient. Sales volumes also vary with weather, declining in mild years. Many state net-metering laws allow consumers installing rooftop solar arrays to incur net-bills for zero or very few kilowatt-hours, depending on the geographic location and the design of the net-metering tariff. To improve revenue stability, and to collect distribution system costs from PV customers, some utilities are arguing that "fixed" costs should be recovered in fixed customer charges. Some utilities are seeking customer charges of $20/month or more. In one extreme case, Madison Gas and Electric Company proposed a $69/month customer charge, to recover all costs except for fuel and purchased power expenses.[4] The Wisconsin PUC recently voted 2-1 to approve an increase in the customer charge to

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1 Rich Sedano, Janine Migden-Ostrander, Brenda Hausauer and Camille Kadoch provided reviews.

2 Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§2601-2645 (1978). Available at: http://www.gpo.gov/fdsys/pkg/STATUTE-92/pdf/STATUTE-92-Pg3117.pdf.

3 WUTC v. Puget Sound Power and Light Company, Cause U-89-2688-T, Third Supp. Order, P. 71, 1990.

$19/month for Wisconsin Public Service Company.[5]

An electric utility has a defined revenue requirement, determined by their regulator. A higher customer charge therefore means a lower per-kWh rate will be required. This has important impacts on the utility and its customers. Utility revenue is stabilized by a high customer charge, independent of weather, conservation, or other impacts on sales. However, the impacts on customers of high customer charges can be inconsistent with policy objectives:

- Small-use customers, such as apartment dwellers, low-income households, and second homes will receive much higher electric bills; the vast majority of low-income consumers are also low-use consumers. This is anathema to public policy objectives that normally tend to protect low-income customers and/or reward low usage;
- Urban area residents who use natural gas for space and water heat will receive much higher electric bills;
- Large-use customers, including large single-family homes in suburban and rural areas without access to natural gas most often will receive lower electric bills, depending on the existing utility rate design; and
- The lower per-kWh prices that result when a significant portion of costs are recovered in a fixed monthly customer charge will stimulate consumption. This creates consequences for incremental utility investment and for the environment. It also reduces the economic incentive for careful customer energy management practices and investment in energy efficiency measures by increasing pay-back periods.

There are several ways besides high fixed charges to address utility revenue stability issues:

- **Financial Reserves:** The traditional approach has been to set rates in a manner that recovers distribution and power costs in a per-kWh charge, and expect utilities to have adequate financial reserves to manage the volatility that occurs with weather. This is reflected in the 40% – 50% equity ratios allowed for electric utilities in determining the cost of capital.
- **Frequent rate cases**: If regulators hold rate proceedings every year or two, there is little time for sales volumes to deviate far from the level used to set volumetric rates.
- **Revenue Decoupling:** Many regulators have adopted revenue regulation mechanisms that calculate a true-up at the end of the month or year to align actual revenues with allowed revenues.

All of these methods allow the per-kWh charge to continue to reflect substantially all of the costs of service. By structuring rates this way, regulators preserve the consumer incentive to use electricity wisely.

Rate Designs with Minimum Bill Charges

One alternative to address utility concerns for revenue adequacy in addition to Revenue Regulation and frequent rate cases is a concept known as a "minimum bill." A minimum bill guarantees the utility a minimum annual revenue level from each customer, even if their usage is zero. The vast majority of customers, who consume the overwhelming majority of energy, have usage that exceeds those low thresholds. For these customers, a minimum bill "disappears" when the usage passes that level, and the customer effectively pays a volumetric rate to cover both power supply and distribution costs.

It is important to understand that a very small number of customers will be adversely affected by the minimum bill, because a large majority of all customers have usage in excess of the minimum billed amount. Figure 1 compares the number of customers served at each usage level, and the kilowatt-hours used by those customers at each usage level. Only a few percent of the customers, using less than one percent of the energy, have usage below 150 kWh per month in this illustrative example, and are arguably not making a meaningful contribution to system costs when those costs are built into the per-kWh charge.

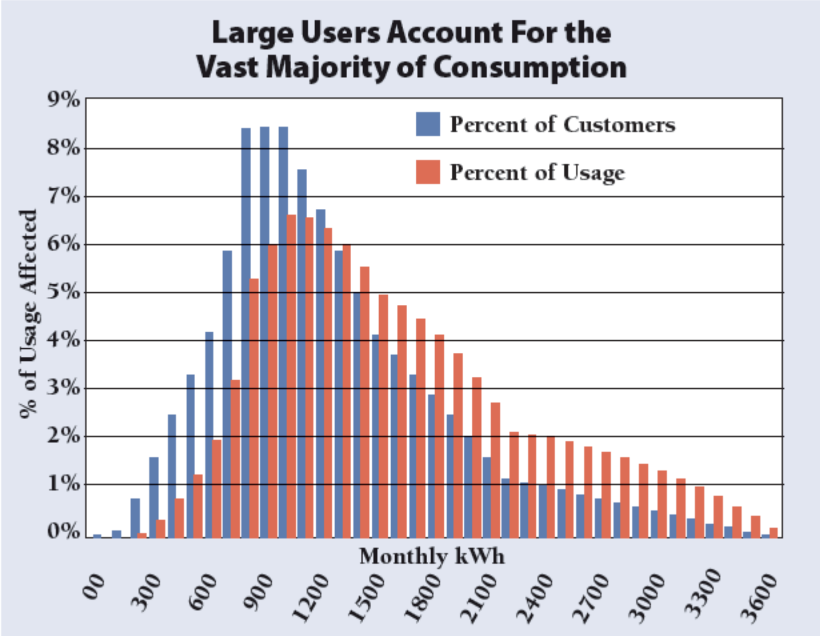
Table 1 compares three example residential rates, all designed to produce the same total level of residential revenue for an illustrative utility with average usage for this example of 1,000 kWh/month/customer.

- **Low Customer Charge:** $5/month, to cover billing and collection
- **High Customer Charge:** $20/month, to cover billing, collection, and a portion of distribution costs
- **Minimum Bill:** $5.00/month to cover billing and collection, with a minimum bill of $20 (which applies if usage falls below 150 kWh/month).

4 Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates, Docket 3270-UR-120, April 9, 2014. Available at: http://psc.wi.gov/apps40/dockets/content/detail.aspx?dockt_id=3270-UR-120.

5 Content, T. (2014, November 6). State regulators approve 83% increase in Green Bay utility's fixed charge. *Milwaukee Journal-Sentinel*. Retrieved from: www.jsonline.com.

Figure 1



This shows that for the average customer, the three rate designs produce almost identical bills. With a high customer charge rate design, because the $20 customer charge is collecting $15 more than the $5 low customer charge, the price per kWh is lower by $0.015/kWh. For the minimum bill rate design, however, less than 1% of kWh sales will typically be to those customers using under 150 kWh/month. This group has historically been limited to unoccupied dwellings; more recently, it has come to include customers with solar PV systems that produce as many kilowatt-hours as they consume, but remain dependent on the grid to serve as a "battery" taking excess production during the day, and supplying power when the sun is not shining.

Therefore, there will not be a lot of revenue recovered by the minimum bill charge, leaving most of the revenue requirement recovered by the volumetric charge. The per-kWh rate would only be reduced by about $0.001/kWh (1%) as a result. Under this rate design, very small-use customers, such as PV customers whose panels produce as many kilowatt-hours as the house uses, would pay slightly higher bills. However, as nearly all usage by customers remains priced at a cost-based rate that includes all of the costs of producing and distributing electricity, the low-use PV customer would have negligible usage charges.

Table 1

	kWh	Low Customer Charge	High Customer Charge	$20 Minimum Bill*
Customer Charge		$5.00	$20.00	$5.00
Minimum Bill				$20.00
Per-kWh Charge		$0.10	$0.085	$0.099
	10 kWh	$6.00	$20.85	$20.00
	100 kWh	$15.00	$28.50	$20.00
Customer Bills	200 kWh	$25.00	$37.00	$24.80
	500 kWh	$55.00	$62.50	$54.50
	1,000 kWh	$105.00	$105.00	$104.00
	1,500 kWh	$155.00	$147.50	$153.50
	2,000 kWh	$205.00	$190.00	$203.00

**The minimum bill will only apply when customer's usage is so low that their bill falls below $20.*

Impact on Usage

Electricity usage varies with the price paid. Higher kWh charges create greater incentives for consumers to turn out unneeded lights, manage thermostat settings, and invest in more efficient appliances, windows, and insulation. There is an economic science tool, price elasticity, which measures the expected change in consumption if prices change. Economists variously estimate the price elasticity of demand for electricity in the range of -0.1 to -0.7, with some long-run estimates going higher. An elasticity of -0.2, meaning that a 1% increase in price results in a 0.2% decrease in the quantity demanded, is considered a conservative estimate of long-run price elasticity.

The high customer charge rate design results in a 15% lower price per kilowatt-hour compared to the low customer charge rate design. Assuming an elasticity of -0.2, that would imply that customers would consume about 3% more electricity (-0.2 elasticity x 15% change in rate = 3% change in usage) as a result of the lower per-kWh price.

The minimum bill rate form, on the other hand, only reduces the price per kWh by 1% compared to the low customer charge rate design; assuming the same elasticity factor, the minimum bill design would increase usage by only about 0.2% among customers using more than the minimum billed quantity, when compared with their usage under the low customer charge rate form.

There is, however, a chance that the very small users might increase their usage up to the 150 kWh minimum. With this $20 minimum bill, customers using less than

150 kWh per month would see no change in their bills if they increased usage up to 150 kwh. But, since only a small percentage of customers use that little power, even if they did so, usage would not increase very much.

Evaluating a choice between a $20 fixed customer charge and a $20 minimum bill charge, we would expect about 15 times as much additional usage under the $20 fixed charge as under the $20 minimum bill charge.

Impact on PV Customers

Part of the concern that is raised by utilities is that customers with solar PV systems are "net-metering" to zero kWh, and paying only the customer charge in a monthly bill. These customers remain dependent on the grid for storage and shaping of their daytime energy production. Solar advocates argue that the grid is receiving a more valuable product – daytime renewable energy – than it is providing to the customers at night from conventional generation, and that this is a form of rough equity.

A minimum bill would ensure that a PV customer with net consumption of zero would still contribute to system costs. In the example, these customers would pay $20 per month. But, rather than distort the rate design for all customers, only the low-consumption consumers would be affected, allowing rates that continue to reflect all system costs to be applied to the overwhelming majority of energy sales.

Advantages and Disadvantages

A rate design that uses a customer charge combined with a kWh charge is simple to understand and administer. It provides a clear price signal for each kWh. If the customer charge is lower, the per-kWh charge is higher. However, the public is used to doing business for other purchases with a zero customer charge – grocery stores, gas stations, and virtually all other retailers only charge customers for what they buy, not for the privilege of being a customer (membership warehouse clubs are exceptions, with fees designed to weed out "browsers" from their stores.) There may also be conflict with intended outcomes for low use customers.

A minimum bill rate design has an advantage in that the per-kWh price is higher, more closely reflecting long-run marginal costs (all costs are variable in the long run). This rate design encourages prudent usage, better aligned with investment impacts from consumption and investment in energy efficiency. This means customer choices about usage and, importantly, energy-related investments, will be informed by electricity prices that reflect long run grid value. The disadvantage is that, for the very small number of customers whose usage is below the "minimum," this rate design provides no disincentive at all to using the minimum amount of electricity. It can be perceived to have a disadvantage of encouraging additional usage by those users with usage below the minimum billed amount, but there are very few of these customers, and their prospective additional usage increase is minimal. Users in this group may argue that the minimum bill is unfair to them.

Finally, a minimum bill rate form ensures that second-homes, which may have no consumption during the off-season, contribute to utility revenues. This is sometimes presented as an economic justice issue, since second homes are generally held only by upper-income consumers.

Conclusion

The primary purpose of utility regulation is to enforce the pricing discipline on monopolies that competitive markets impose on most firms. Competitive firms nearly always recover all of their costs in the price per unit of their products. Therefore, any fixed monthly charge for electricity service represents a deviation from this underlying principle of utility regulation. The most commonly applied customer charges recover only customer-specific costs, such as billing and collection, in a fixed customer charge, leaving all costs of the shared system to be recovered in usage charges.

A regulator seeking to increase the contribution to utility system costs from those customers with minimal consumption can do so with either a higher customer charge, or establishing a minimum bill. The minimum bill option will ensure that all customers contribute to distribution costs, but without significantly stimulating consumption by higher-use customers or raising the bills of lower-income, low-use customers.

Forthcoming in Second Quarter, 2015: *Electric Rate Design for the Utility of the Future*. Watch for this on our website, www.raponline.org

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Duke Energy Progress, LLC

Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental
Exhibit No. 1

Comparison of Rates of Return, Indices, and % Base Revenue

Based on SCP Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.56%		1.00	3.84%	0.70%
Residential	6.26%		0.95	5.84%	2.36%
Small General Service	6.56%		1.00	3.10%	-0.12%
Small General Service - CLR	6.56%		1.00	4.30%	1.44%
Medium General Service	6.67%		1.02	1.59%	-1.14%
Large General Service	6.91%		1.05	1.44%	-0.91%
Seasonal & Intermittent	9.83%	**	1.50	1.01%	-2.08%
Traffic Signal	4.61%	**	0.70	5.84%	3.05%
Outdoor Lighting - ALS	15.54%	**	2.37	0.95%	-3.75%
Outdoor Lighting - SLS	2.37%	**	0.36	5.84%	1.11%
Sports Field Lighting	9.91%	**	1.51	1.01%	-2.45%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended

+/- 10% band of reasonableness.

Duke Energy Progress, LLC

Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental
Exhibit No. 1

Comparison of Rates of Return, Indices, and % Base Revenue

Based on SWPA Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.56%		1.00	3.84%	0.70%
Residential	6.13%		0.93	5.75%	2.27%
Small General Service	6.99%		1.07	1.32%	-1.90%
Small General Service - CLR	5.42%	**	0.83	5.74%	2.88%
Medium General Service	7.33%	**	1.12	1.09%	-1.64%
Large General Service	6.56%		1.00	3.33%	0.98%
Seasonal & Intermittent	8.77%	**	1.34	1.03%	-2.07%
Traffic Signal	2.85%	**	0.44	5.84%	3.04%
Outdoor Lighting - ALS	12.63%	**	1.93	0.88%	-3.84%
Outdoor Lighting - SLS	1.79%	**	0.27	5.84%	1.09%
Sports Field Lighting	7.14%		1.09	1.25%	-2.23%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended

+/- 10% band of reasonableness.

Duke Energy Progress, LLC

Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental
Exhibit No. 1
Page 3 of 3

Comparison of Rates of Return, Indices, and % Base Revenue

Based on WCP Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.56%		1.00	3.84%	0.70%
Residential	3.95%	**	0.60	5.84%	2.35%
Small General Service	6.74%		1.03	2.89%	-0.33%
Small General Service - CLR	6.57%		1.00	5.45%	2.60%
Medium General Service	11.33%	**	1.73	1.70%	-1.02%
Large General Service	15.26%	**	2.33	1.33%	-1.00%
Seasonal & Intermittent	12.86%	**	1.96	1.49%	-1.59%
Traffic Signal	4.24%	**	0.65	5.84%	3.05%
Outdoor Lighting - ALS	15.20%	**	2.32	1.42%	-3.28%
Outdoor Lighting - SLS	2.22%	**	0.34	5.84%	1.09%
Sports Field Lighting	9.74%	**	1.49	1.82%	-1.65%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended
+/- 10% band of reasonableness.

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental Exhibit 2

Base Case - No Revenue Change -SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,895	$ 222,039	$ 4,022	$ 836,620	$ 510,431	$ 4,877	$ 474	$ 59,747	$ 24,858	$ 191
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 586,335	$ 282,232	$ 40,160	$ 568	$ 149,450	$ 82,395	$ 1,371	$ 37	$ 27,400	$ 2,666	$ 56
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 586,335	$ 282,232	$ 40,160	$ 568	$ 149,450	$ 82,395	$ 1,371	$ 37	$ 27,400	$ 2,666	$ 56
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,720,530	$ 692,204	$ 10,679	$ 2,390,383	$ 1,272,729	$ 14,311	$ 1,258	$ 178,922	$ 159,299	$ 581
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,726,752	$ 692,957	$ 10,690	$ 2,392,983	$ 1,274,113	$ 14,327	$ 1,259	$ 179,117	$ 159,472	$ 581
8	**Rate of Return (before change)**	5.62%	4.93%	5.80%	5.32%	6.25%	6.47%	9.58%	2.94%	15.31%	1.67%	9.67%
9	**Rate of Return Index (before change)**	1.00	0.88	1.03	0.95	1.11	1.15	1.71	0.52	2.73	0.30	1.72
10	**Rate of Return (after change)**	5.61%	4.93%	5.80%	5.32%	6.25%	6.47%	9.57%	2.93%	15.30%	1.67%	9.66%
11	**Rate of Return Index (after change)**	1.00	0.88	1.03	0.95	1.11	1.15	1.71	0.52	2.73	0.30	1.72
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

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Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental Exhibit 2

Equal Rates of Return for all Classes - SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,895	$ 222,039	$ 4,022	$ 836,620	$ 510,431	$ 4,877	$ 474	$ 59,747	$ 24,858	$ 191
2	**Proposed Revenue Change**	$ 129,085	$ 121,699	$ 6,875	$ 173	$ 9,681	$ 1,467	$ (564)	$ 60	$ (20,457)	$ 10,174	$ (24)
3	**Net Income Before Increase**	$ 586,335	$ 282,232	$ 40,160	$ 568	$ 149,450	$ 82,395	$ 1,371	$ 37	$ 27,400	$ 2,666	$ 56
4	**Change in Net Income**	$ 98,811	$ 93,157	$ 5,263	$ 132	$ 7,411	$ 1,123	$ (431)	$ 46	$ (15,659)	$ 7,788	$ (18)
5	**Total Net Income**	$ 685,146	$ 375,389	$ 45,423	$ 701	$ 156,860	$ 83,518	$ 939	$ 83	$ 11,741	$ 10,453	$ 38
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,720,530	$ 692,204	$ 10,679	$ 2,390,383	$ 1,272,729	$ 14,311	$ 1,258	$ 178,922	$ 159,299	$ 581
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,726,752	$ 692,957	$ 10,690	$ 2,392,983	$ 1,274,113	$ 14,327	$ 1,259	$ 179,117	$ 159,472	$ 581
8	**Rate of Return (before change)**	5.62%	4.93%	5.80%	5.32%	6.25%	6.47%	9.58%	2.94%	15.31%	1.67%	9.67%
9	**Rate of Return Index (before change)**	1.00	0.88	1.03	0.95	1.11	1.15	1.71	0.52	2.73	0.30	1.72
10	**Rate of Return (after change)**	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Base Revenue**	3.84%	7.15%	3.10%	4.30%	1.16%	0.29%	-11.56%	12.58%	-34.24%	40.93%	-12.36%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

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Floyd Supplemental Exhibit 2
Page 3 of 4

Class Revenue Changes Equal to NC Retail Change - SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,895	$ 222,039	$ 4,022	$ 836,620	$ 510,431	$ 4,877	$ 474	$ 59,747	$ 24,858	$ 191
2	**Proposed Revenue Change**	$ 129,085	$ 121,699	$ 6,875	$ 173	$ 9,681	$ 1,467	$ (564)	$ 60	$ (20,457)	$ 10,174	$ (24)
3	**Net Income Before Increase**	$ 586,335	$ 282,232	$ 40,160	$ 568	$ 149,450	$ 82,395	$ 1,371	$ 37	$ 27,400	$ 2,666	$ 56
4	**Change in Net Income**	$ 98,811	$ 93,157	$ 5,263	$ 132	$ 7,411	$ 1,123	$ (431)	$ 46	$ (15,659)	$ 7,788	$ (18)
5	**Total Net Income**	$ 685,146	$ 375,389	$ 45,423	$ 701	$ 156,860	$ 83,518	$ 939	$ 83	$ 11,741	$ 10,453	$ 38
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,720,530	$ 692,204	$ 10,679	$ 2,390,383	$ 1,272,729	$ 14,311	$ 1,258	$ 178,922	$ 159,299	$ 581
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,726,752	$ 692,957	$ 10,690	$ 2,392,983	$ 1,274,113	$ 14,327	$ 1,259	$ 179,117	$ 159,472	$ 581
8	**Rate of Return (before change)**	5.62%	4.93%	5.80%	5.32%	6.25%	6.47%	9.58%	2.94%	15.31%	1.67%	9.67%
9	**Rate of Return Index (before change)**	1.00	0.88	1.03	0.95	1.11	1.15	1.71	0.52	2.73	0.30	1.72
10	**Rate of Return (after change)**	6.56%	5.80%	6.74%	6.42%	7.27%	7.64%	10.57%	4.04%	16.28%	2.13%	10.62%
11	**Rate of Return Index (after change)**	1.00	0.88	1.03	0.98	1.11	1.17	1.61	0.62	2.48	0.32	1.62
12	**Percent Change in Base Revenue**	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental Exhibit 2

Public Staff Recommended Revenue Distribution- SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,895	$ 222,039	$ 4,022	$ 836,620	$ 510,431	$ 4,877	$ 474	$ 59,747	$ 24,858	$ 191
2	**Proposed Revenue Change**	$ 129,085	$ 99,258	$ 6,875	$ 173	$ 13,332	$ 7,348	$ 49	$ 28	$ 568	$ 1,452	$ 2
3	**Net Income Before Increase**	$ 586,335	$ 282,232	$ 40,160	$ 568	$ 149,450	$ 82,395	$ 1,371	$ 37	$ 27,400	$ 2,666	$ 56
4	**Change in Net Income**	$ 98,811	$ 75,979	$ 5,263	$ 132	$ 10,205	$ 5,625	$ 38	$ 21	$ 435	$ 1,111	$ 1
5	**Total Net Income**	$ 685,146	$ 358,211	$ 45,423	$ 701	$ 159,655	$ 88,020	$ 1,408	$ 58	$ 27,835	$ 3,777	$ 58
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,720,530	$ 692,204	$ 10,679	$ 2,390,383	$ 1,272,729	$ 14,311	$ 1,258	$ 178,922	$ 159,299	$ 581
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,726,752	$ 692,957	$ 10,690	$ 2,392,983	$ 1,274,113	$ 14,327	$ 1,259	$ 179,117	$ 159,472	$ 581
8	**Rate of Return (before change)**	5.62%	4.93%	5.80%	5.32%	6.25%	6.47%	9.58%	2.94%	15.31%	1.67%	9.67%
9	**Rate of Return Index (before change)**	1.00	0.88	1.03	0.95	1.11	1.15	1.71	0.52	2.73	0.30	1.72
10	**Rate of Return (after change)**	6.56%	6.26%	6.56%	6.56%	6.67%	6.91%	9.83%	4.61%	15.54%	2.37%	9.91%
11	**Rate of Return Index (after change)**	1.00	0.95	1.00	1.00	1.02	1.05	1.50	0.70	2.37	0.36	1.51
12	**Percent Change in Base Revenue**	3.84%	5.84%	3.10%	4.30%	1.59%	1.44%	1.01%	5.84%	0.95%	5.84%	1.01%
13	**Staff's Proposed EDIT-2 Credit**	$ (105,421)	$ (59,177)	$ (7,144)	$ (115)	$ (22,852)	$ (11,979)	$ (151)	$ (13)	$ (2,808)	$ (1,177)	$ (7)
14	**Percent Change in Revenue with EDIT-2 Credit**	0.70%	2.36%	-0.12%	1.44%	-1.14%	-0.91%	-2.08%	3.05%	-3.75%	1.11%	-2.45%

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental Exhibit 3

Base Case - No Revenue Change -SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,734	$ 222,337	$ 4,013	$ 837,447	$ 509,753	$ 4,869	$ 472	$ 59,550	$ 24,788	$ 190
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 586,335	$ 279,742	$ 43,828	$ 457	$ 159,862	$ 74,196	$ 1,282	$ 19	$ 25,020	$ 1,881	$ 46
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 586,335	$ 279,742	$ 43,828	$ 457	$ 159,862	$ 74,196	$ 1,282	$ 19	$ 25,020	$ 1,881	$ 46
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,783,022	$ 658,479	$ 11,687	$ 2,273,875	$ 1,328,659	$ 15,049	$ 1,417	$ 200,980	$ 167,056	$ 672
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,789,312	$ 659,195	$ 11,700	$ 2,276,348	$ 1,330,104	$ 15,065	$ 1,419	$ 201,198	$ 167,238	$ 673
8	**Rate of Return (before change)**	5.62%	4.84%	6.66%	3.91%	7.03%	5.58%	8.52%	1.37%	12.45%	1.13%	6.87%
9	**Rate of Return Index (before change)**	1.00	0.86	1.19	0.70	1.25	0.99	1.52	0.24	2.22	0.20	1.22
10	**Rate of Return (after change)**	5.61%	4.83%	6.65%	3.91%	7.02%	5.58%	8.51%	1.36%	12.44%	1.12%	6.87%
11	**Rate of Return Index (after change)**	1.00	0.86	1.19	0.70	1.25	0.99	1.52	0.24	2.22	0.20	1.22
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental Exhibit 3

Equal Rates of Return for all Classes - SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,734	$ 222,337	$ 4,013	$ 837,447	$ 509,753	$ 4,869	$ 472	$ 59,550	$ 24,788	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 130,309	$ (807)	$ 405	$ (13,910)	$ 16,973	$ (385)	$ 96	$ (15,457)	$ 11,863	$ (3)
3	**Net Income Before Increase**	$ 586,335	$ 279,742	$ 43,828	$ 457	$ 159,862	$ 74,196	$ 1,282	$ 19	$ 25,020	$ 1,881	$ 46
4	**Change in Net Income**	$ 98,811	$ 99,748	$ (618)	$ 310	$ (10,648)	$ 12,993	$ (295)	$ 74	$ (11,832)	$ 9,081	$ (2)
5	**Total Net Income**	$ 685,146	$ 379,490	$ 43,210	$ 767	$ 149,215	$ 87,188	$ 988	$ 93	$ 13,189	$ 10,962	$ 44
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,783,022	$ 658,479	$ 11,687	$ 2,273,875	$ 1,328,659	$ 15,049	$ 1,417	$ 200,980	$ 167,056	$ 672
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,789,312	$ 659,195	$ 11,700	$ 2,276,348	$ 1,330,104	$ 15,065	$ 1,419	$ 201,198	$ 167,238	$ 673
8	**Rate of Return (before change)**	5.62%	4.84%	6.66%	3.91%	7.03%	5.58%	8.52%	1.37%	12.45%	1.13%	6.87%
9	**Rate of Return Index (before change)**	1.00	0.86	1.19	0.70	1.25	0.99	1.52	0.24	2.22	0.20	1.22
10	**Rate of Return (after change)**	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Base Revenue**	3.84%	7.66%	-0.36%	10.08%	-1.66%	3.33%	-7.91%	20.38%	-25.96%	47.86%	-1.44%

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental Exhibit 3

Class Revenue Changes Equal to NC Retail Change - SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,734	$ 222,337	$ 4,013	$ 837,447	$ 509,753	$ 4,869	$ 472	$ 59,550	$ 24,788	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 130,309	$ (807)	$ 405	$ (13,910)	$ 16,973	$ (385)	$ 96	$ (15,457)	$ 11,863	$ (3)
3	**Net Income Before Increase**	$ 586,335	$ 279,742	$ 43,828	$ 457	$ 159,862	$ 74,196	$ 1,282	$ 19	$ 25,020	$ 1,881	$ 46
4	**Change in Net Income**	$ 98,811	$ 99,748	$ (618)	$ 310	$ (10,648)	$ 12,993	$ (295)	$ 74	$ (11,832)	$ 9,081	$ (2)
5	**Total Net Income**	$ 685,146	$ 379,490	$ 43,210	$ 767	$ 149,215	$ 87,188	$ 988	$ 93	$ 13,189	$ 10,962	$ 44
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,783,022	$ 658,479	$ 11,687	$ 2,273,875	$ 1,328,659	$ 15,049	$ 1,417	$ 200,980	$ 167,056	$ 672
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,789,312	$ 659,195	$ 11,700	$ 2,276,348	$ 1,330,104	$ 15,065	$ 1,419	$ 201,198	$ 167,238	$ 673
8	**Rate of Return (before change)**	5.62%	4.84%	6.66%	3.91%	7.03%	5.58%	8.52%	1.37%	12.45%	1.13%	6.87%
9	**Rate of Return Index (before change)**	1.00	0.86	1.19	0.70	1.25	0.99	1.52	0.24	2.22	0.20	1.22
10	**Rate of Return (after change)**	6.56%	5.69%	7.64%	4.92%	8.10%	6.70%	9.46%	2.34%	13.30%	1.56%	7.69%
11	**Rate of Return Index (after change)**	1.00	0.87	1.17	0.75	1.24	1.02	1.44	0.36	2.03	0.24	1.17
12	**Percent Change in Base Revenue**	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental Exhibit 3
Page 4 of 4

Public Staff Recommended Revenue Distribution- SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,734	$ 222,337	$ 4,013	$ 837,447	$ 509,753	$ 4,869	$ 472	$ 59,550	$ 24,788	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 97,791	$ 2,930	$ 231	$ 9,109	$ 16,973	$ 50	$ 28	$ 524	$ 1,448	$ 2
3	**Net Income Before Increase**	$ 586,335	$ 279,742	$ 43,828	$ 457	$ 159,862	$ 74,196	$ 1,282	$ 19	$ 25,020	$ 1,881	$ 46
4	**Change in Net Income**	$ 98,811	$ 74,856	$ 2,243	$ 176	$ 6,973	$ 12,993	$ 38	$ 21	$ 401	$ 1,108	$ 2
5	**Total Net Income**	$ 685,146	$ 354,598	$ 46,071	$ 634	$ 166,835	$ 87,188	$ 1,321	$ 40	$ 25,421	$ 2,990	$ 48
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,783,022	$ 658,479	$ 11,687	$ 2,273,875	$ 1,328,659	$ 15,049	$ 1,417	$ 200,980	$ 167,056	$ 672
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,789,312	$ 659,195	$ 11,700	$ 2,276,348	$ 1,330,104	$ 15,065	$ 1,419	$ 201,198	$ 167,238	$ 673
8	**Rate of Return (before change)**	5.62%	4.84%	6.66%	3.91%	7.03%	5.58%	8.52%	1.37%	12.45%	1.13%	6.87%
9	**Rate of Return Index (before change)**	1.00	0.86	1.19	0.70	1.25	0.99	1.52	0.24	2.22	0.20	1.22
10	**Rate of Return (after change)**	6.56%	6.13%	6.99%	5.42%	7.33%	6.56%	8.77%	2.85%	12.63%	1.79%	7.14%
11	**Rate of Return Index (after change)**	1.00	0.93	1.07	0.83	1.12	1.00	1.34	0.44	1.93	0.27	1.09
12	**Percent Change in Base Revenue**	3.84%	5.75%	1.32%	5.74%	1.09%	3.33%	1.03%	5.84%	0.88%	5.84%	1.25%
13	**Staff's Proposed EDIT-2 Credit**	$ (105,421)	$ (59,177)	$ (7,144)	$ (115)	$ (22,852)	$ (11,979)	$ (151)	$ (13)	$ (2,808)	$ (1,177)	$ (7)
14	**Percent Change in Revenue with EDIT-2 Credit**	0.70%	2.27%	-1.90%	2.88%	-1.64%	0.98%	-2.07%	3.04%	-3.84%	1.09%	-2.23%

I/A

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Base Case - No Revenue Change -WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,693,149	$ 222,116	$ 4,021	$ 840,866	$ 513,902	$ 4,891	$ 473	$ 59,717	$ 24,828	$ 190
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 586,335	$ 187,827	$ 41,145	$ 546	$ 201,196	$ 124,357	$ 1,554	$ 34	$ 27,122	$ 2,500	$ 55
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 586,335	$ 187,827	$ 41,145	$ 546	$ 201,196	$ 124,357	$ 1,554	$ 34	$ 27,122	$ 2,500	$ 55
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 6,669,267	$ 682,556	$ 10,866	$ 1,870,538	$ 848,215	$ 12,505	$ 1,287	$ 182,546	$ 162,523	$ 592
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 6,676,520	$ 683,299	$ 10,878	$ 1,872,572	$ 849,137	$ 12,519	$ 1,288	$ 182,745	$ 162,700	$ 593
8	**Rate of Return (before change)**	5.62%	2.82%	6.03%	5.03%	10.76%	14.66%	12.42%	2.60%	14.86%	1.54%	9.30%
9	**Rate of Return Index (before change)**	1.00	0.50	1.07	0.90	1.92	2.61	2.21	0.46	2.65	0.27	1.66
10	**Rate of Return (after change)**	5.61%	2.81%	6.02%	5.02%	10.74%	14.65%	12.41%	2.60%	14.84%	1.54%	9.29%
11	**Rate of Return Index (after change)**	1.00	0.50	1.07	0.90	1.92	2.61	2.21	0.46	2.65	0.27	1.66
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental Exhibit 4

Equal Rates of Return for all Classes - WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,693,149	$ 222,116	$ 4,021	$ 840,866	$ 513,902	$ 4,891	$ 473	$ 59,717	$ 24,828	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 326,361	$ 4,763	$ 218	$ (102,484)	$ (89,743)	$ (958)	$ 67	$ (19,783)	$ 10,666	$ (21)
3	**Net Income Before Increase**	$ 586,335	$ 187,827	$ 41,145	$ 546	$ 201,196	$ 124,357	$ 1,554	$ 34	$ 27,122	$ 2,500	$ 55
4	**Change in Net Income**	$ 98,811	$ 249,820	$ 3,646	$ 167	$ (78,448)	$ (68,696)	$ (733)	$ 51	$ (15,144)	$ 8,165	$ (16)
5	**Total Net Income**	$ 685,146	$ 437,647	$ 44,790	$ 713	$ 122,747	$ 55,661	$ 821	$ 84	$ 11,979	$ 10,665	$ 39
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 6,669,267	$ 682,556	$ 10,866	$ 1,870,538	$ 848,215	$ 12,505	$ 1,287	$ 182,546	$ 162,523	$ 592
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 6,676,520	$ 683,299	$ 10,878	$ 1,872,572	$ 849,137	$ 12,519	$ 1,288	$ 182,745	$ 162,700	$ 593
8	**Rate of Return (before change)**	5.62%	2.82%	6.03%	5.03%	10.76%	14.66%	12.42%	2.60%	14.86%	1.54%	9.30%
9	**Rate of Return Index (before change)**	1.00	0.50	1.07	0.90	1.92	2.61	2.21	0.46	2.65	0.27	1.66
10	**Rate of Return (after change)**	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Base Revenue**	3.84%	19.28%	2.14%	5.42%	-12.19%	-17.46%	-19.58%	14.05%	-33.13%	42.96%	-11.14%

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental Exhibit 4

Class Revenue Changes Equal to NC Retail Change - WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,693,149	$ 222,116	$ 4,021	$ 840,866	$ 513,902	$ 4,891	$ 473	$ 59,717	$ 24,828	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 326,361	$ 4,763	$ 218	$ (102,484)	$ (89,743)	$ (958)	$ 67	$ (19,783)	$ 10,666	$ (21)
3	**Net Income Before Increase**	$ 586,335	$ 187,827	$ 41,145	$ 546	$ 201,196	$ 124,357	$ 1,554	$ 34	$ 27,122	$ 2,500	$ 55
4	**Change in Net Income**	$ 98,811	$ 249,820	$ 3,646	$ 167	$ (78,448)	$ (68,696)	$ (733)	$ 51	$ (15,144)	$ 8,165	$ (16)
5	**Total Net Income**	$ 685,146	$ 437,647	$ 44,790	$ 713	$ 122,747	$ 55,661	$ 821	$ 84	$ 11,979	$ 10,665	$ 39
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 6,669,267	$ 682,556	$ 10,866	$ 1,870,538	$ 848,215	$ 12,505	$ 1,287	$ 182,546	$ 162,523	$ 592
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 6,676,520	$ 683,299	$ 10,878	$ 1,872,572	$ 849,137	$ 12,519	$ 1,288	$ 182,745	$ 162,700	$ 593
8	**Rate of Return (before change)**	5.62%	2.82%	6.03%	5.03%	10.76%	14.66%	12.42%	2.60%	14.86%	1.54%	9.30%
9	**Rate of Return Index (before change)**	1.00	0.50	1.07	0.90	1.92	2.61	2.21	0.46	2.65	0.27	1.66
10	**Rate of Return (after change)**	6.56%	3.56%	6.98%	6.11%	12.06%	16.42%	13.56%	3.68%	15.80%	1.98%	10.24%
11	**Rate of Return Index (after change)**	1.00	0.54	1.06	0.93	1.84	2.51	2.07	0.56	2.41	0.30	1.56
12	**Percent Change in Base Revenue**	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Supplemental Exhibit 4

Public Staff Recommended Revenue Distribution- WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,693,149	$ 222,116	$ 4,021	$ 840,866	$ 513,902	$ 4,891	$ 473	$ 59,717	$ 24,828	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 98,898	$ 6,413	$ 219	$ 14,317	$ 6,837	$ 73	$ 28	$ 849	$ 1,449	$ 3
3	**Net Income Before Increase**	$ 586,335	$ 187,827	$ 41,145	$ 546	$ 201,196	$ 124,357	$ 1,554	$ 34	$ 27,122	$ 2,500	$ 55
4	**Change in Net Income**	$ 98,811	$ 75,703	$ 4,909	$ 168	$ 10,959	$ 5,234	$ 56	$ 21	$ 650	$ 1,109	$ 3
5	**Total Net Income**	$ 685,146	$ 263,530	$ 46,053	$ 714	$ 212,154	$ 129,590	$ 1,609	$ 55	$ 27,772	$ 3,609	$ 58
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 6,669,267	$ 682,556	$ 10,866	$ 1,870,538	$ 848,215	$ 12,505	$ 1,287	$ 182,546	$ 162,523	$ 592
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 6,676,520	$ 683,299	$ 10,878	$ 1,872,572	$ 849,137	$ 12,519	$ 1,288	$ 182,745	$ 162,700	$ 593
8	**Rate of Return (before change)**	5.62%	2.82%	6.03%	5.03%	10.76%	14.66%	12.42%	2.60%	14.86%	1.54%	9.30%
9	**Rate of Return Index (before change)**	1.00	0.50	1.07	0.90	1.92	2.61	2.21	0.46	2.65	0.27	1.66
10	**Rate of Return (after change)**	6.56%	3.95%	6.74%	6.57%	11.33%	15.26%	12.86%	4.24%	15.20%	2.22%	9.74%
11	**Rate of Return Index (after change)**	1.00	0.60	1.03	1.00	1.73	2.33	1.96	0.65	2.32	0.34	1.49
12	**Percent Change in Base Revenue**	3.84%	5.84%	2.89%	5.45%	1.70%	1.33%	1.49%	5.84%	1.42%	5.84%	1.82%
13	**Staff's Proposed EDIT-2 Credit**	$ (105,421)	$ (59,177)	$ (7,144)	$ (115)	$ (22,852)	$ (11,979)	$ (151)	$ (13)	$ (2,808)	$ (1,177)	$ (7)
14	**Percent Change in Revenue with EDIT-2 Credit**	0.70%	2.35%	-0.33%	2.60%	-1.02%	-1.00%	-1.59%	3.05%	-3.28%	1.09%	-1.65%

Duke Energy Progress, LLC

Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental
Exhibit No. 1
Page 1 of 3

Comparison of Rates of Return, Indices, and % Base Revenue

Based on SCP Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.93%		1.00	7.90%	2.89%
Residential	6.51%		0.94	9.52%	3.95%
Small General Service	7.03%		1.01	7.56%	2.41%
Small General Service - CLR	6.93%		1.00	8.16%	3.60%
Medium General Service	7.21%		1.04	6.11%	1.74%
Large General Service	7.58%		1.09	6.12%	2.37%
Seasonal & Intermittent	9.72%	**	1.40	3.00%	-1.95%
Traffic Signal	5.03%	**	0.73	9.90%	5.44%
Outdoor Lighting - ALS	15.47%	**	2.23	3.00%	-5.06%
Outdoor Lighting - SLS	2.54%	**	0.37	9.90%	3.62%
Sports Field Lighting	9.81%	**	1.41	3.00%	-2.54%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended

+/- 10% band of reasonableness.

Duke Energy Progress, LLC

Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental
Exhibit No. 1
Page 2 of 3

Comparison of Rates of Return, Indices, and % Base Revenue

Based on SWPA Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.93%		1.00	7.90%	2.89%
Residential	6.48%		0.93	9.90%	4.33%
Small General Service	7.57%		1.09	6.05%	0.91%
Small General Service - CLR	5.83%	**	0.84	9.90%	5.33%
Medium General Service	7.82%	**	1.13	5.30%	0.94%
Large General Service	6.80%		0.98	6.70%	2.94%
Seasonal & Intermittent	8.90%	**	1.28	4.00%	-0.95%
Traffic Signal	3.22%	**	0.46	9.90%	5.43%
Outdoor Lighting - ALS	12.81%	**	1.85	4.00%	-4.08%
Outdoor Lighting - SLS	1.95%	**	0.28	9.90%	3.61%
Sports Field Lighting	7.50%		1.08	5.37%	-0.20%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended
+/- 10% band of reasonableness.

Duke Energy Progress, LLC

Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental
Exhibit No. 1
Page 3 of 3

Comparison of Rates of Return, Indices, and % Base Revenue

Based on WCP Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.93%		1.00	7.90%	2.89%
Residential	4.23%	**	0.61	9.90%	4.31%
Small General Service	7.14%		1.03	7.00%	1.86%
Small General Service - CLR	7.04%		1.02	9.70%	5.13%
Medium General Service	11.96%	**	1.72	6.00%	1.65%
Large General Service	15.85%	**	2.29	5.06%	1.33%
Seasonal & Intermittent	13.33%	**	1.92	5.50%	0.57%
Traffic Signal	4.65%	**	0.67	9.90%	5.44%
Outdoor Lighting - ALS	15.51%	**	2.24	5.00%	-3.06%
Outdoor Lighting - SLS	2.39%	**	0.34	9.90%	3.62%
Sports Field Lighting	9.93%	**	1.43	5.00%	-0.55%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended
+/- 10% band of reasonableness.

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Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 2

Base Case - No Revenue Change -SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,355,753	$ 1,696,647	$ 221,485	$ 4,012	$ 834,531	$ 509,156	$ 4,865	$ 472	$ 59,598	$ 24,796	$ 190
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 531,135	$ 254,084	$ 36,542	$ 500	$ 135,783	$ 73,909	$ 1,299	$ 28	$ 26,706	$ 2,230	$ 53
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 531,135	$ 254,084	$ 36,542	$ 500	$ 135,783	$ 73,909	$ 1,299	$ 28	$ 26,706	$ 2,230	$ 53
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,563,824	$ 5,787,882	$ 700,354	$ 10,804	$ 2,418,527	$ 1,287,714	$ 14,480	$ 1,273	$ 181,029	$ 161,174	$ 587
7	**Staff's Proposed Rate Base**	$ 10,587,216	$ 5,800,699	$ 701,905	$ 10,828	$ 2,423,882	$ 1,290,565	$ 14,512	$ 1,275	$ 181,430	$ 161,531	$ 589
8	**Rate of Return (before change)**	5.03%	4.39%	5.22%	4.63%	5.61%	5.74%	8.97%	2.23%	14.75%	1.38%	9.09%
9	**Rate of Return Index (before change)**	1.00	0.87	1.04	0.92	1.12	1.14	1.78	0.44	2.93	0.28	1.81
10	**Rate of Return (after change)**	5.03%	4.39%	5.22%	4.63%	5.61%	5.74%	8.97%	2.23%	14.75%	1.38%	9.09%
11	**Rate of Return Index (after change)**	1.00	0.87	1.04	0.92	1.12	1.14	1.79	0.44	2.93	0.27	1.81
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 2

Equal Rates of Return for all Classes - SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,355,753	$ 1,696,647	$ 221,485	$ 4,012	$ 834,531	$ 509,156	$ 4,865	$ 472	$ 59,598	$ 24,796	$ 190
2	**Proposed Revenue Change**	$ 265,117	$ 193,492	$ 15,840	$ 327	$ 42,168	$ 20,345	$ (383)	$ 78	$ (18,454)	$ 11,719	$ (16)
3	**Net Income Before Increase**	$ 531,135	$ 254,084	$ 36,542	$ 500	$ 135,783	$ 73,909	$ 1,299	$ 28	$ 26,706	$ 2,230	$ 53
4	**Change in Net Income**	$ 202,939	$ 148,112	$ 12,125	$ 251	$ 32,279	$ 15,573	$ (293)	$ 60	$ (14,126)	$ 8,970	$ (13)
5	**Total Net Income**	$ 734,074	$ 402,197	$ 48,667	$ 751	$ 168,062	$ 89,482	$ 1,006	$ 88	$ 12,580	$ 11,200	$ 41
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,563,824	$ 5,787,882	$ 700,354	$ 10,804	$ 2,418,527	$ 1,287,714	$ 14,480	$ 1,273	$ 181,029	$ 161,174	$ 587
7	**Staff's Proposed Rate Base**	$ 10,587,216	$ 5,800,699	$ 701,905	$ 10,828	$ 2,423,882	$ 1,290,565	$ 14,512	$ 1,275	$ 181,430	$ 161,531	$ 589
8	**Rate of Return (before change)**	5.03%	4.39%	5.22%	4.63%	5.61%	5.74%	8.97%	2.23%	14.75%	1.38%	9.09%
9	**Rate of Return Index (before change)**	1.00	0.87	1.04	0.92	1.12	1.14	1.78	0.44	2.93	0.28	1.81
10	**Rate of Return (after change)**	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Base Revenue**	7.90%	11.40%	7.15%	8.16%	5.05%	4.00%	-7.87%	16.60%	-30.96%	47.26%	-8.64%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 2
Page 3 of 4

Class Revenue Changes Equal to NC Retail Change - SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,355,753	$ 1,696,647	$ 221,485	$ 4,012	$ 834,531	$ 509,156	$ 4,865	$ 472	$ 59,598	$ 24,796	$ 190
2	**Proposed Revenue Change**	$ 265,117	$ 193,492	$ 15,840	$ 327	$ 42,168	$ 20,345	$ (383)	$ 78	$ (18,454)	$ 11,719	$ (16)
3	**Net Income Before Increase**	$ 531,135	$ 254,084	$ 36,542	$ 500	$ 135,783	$ 73,909	$ 1,299	$ 28	$ 26,706	$ 2,230	$ 53
4	**Change in Net Income**	$ 202,939	$ 148,112	$ 12,125	$ 251	$ 32,279	$ 15,573	$ (293)	$ 60	$ (14,126)	$ 8,970	$ (13)
5	**Total Net Income**	$ 734,074	$ 402,197	$ 48,667	$ 751	$ 168,062	$ 89,482	$ 1,006	$ 88	$ 12,580	$ 11,200	$ 41
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,563,824	$ 5,787,882	$ 700,354	$ 10,804	$ 2,418,527	$ 1,287,714	$ 14,480	$ 1,273	$ 181,029	$ 161,174	$ 587
7	**Staff's Proposed Rate Base**	$ 10,587,216	$ 5,800,699	$ 701,905	$ 10,828	$ 2,423,882	$ 1,290,565	$ 14,512	$ 1,275	$ 181,430	$ 161,531	$ 589
8	**Rate of Return (before change)**	5.03%	4.39%	5.22%	4.63%	5.61%	5.74%	8.97%	2.23%	14.75%	1.38%	9.09%
9	**Rate of Return Index (before change)**	1.00	0.87	1.04	0.92	1.12	1.14	1.78	0.44	2.93	0.28	1.81
10	**Rate of Return (after change)**	6.93%	6.15%	7.11%	6.86%	7.68%	8.11%	10.98%	4.47%	16.71%	2.31%	11.02%
11	**Rate of Return Index (after change)**	1.00	0.89	1.03	0.99	1.11	1.17	1.58	0.64	2.41	0.33	1.59
12	**Percent Change in Base Revenue**	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%

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Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 2

Public Staff Recommended Revenue Distribution- SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,355,753	$ 1,696,647	$ 221,485	$ 4,012	$ 834,531	$ 509,156	$ 4,865	$ 472	$ 59,598	$ 24,796	$ 190
2	**Proposed Revenue Change**	$ 265,117	$ 161,449	$ 16,740	$ 327	$ 50,994	$ 31,166	$ 146	$ 47	$ 1,788	$ 2,455	$ 6
3	**Net Income Before Increase**	$ 531,135	$ 254,084	$ 36,542	$ 500	$ 135,783	$ 73,909	$ 1,299	$ 28	$ 26,706	$ 2,230	$ 53
4	**Change in Net Income**	$ 202,939	$ 123,584	$ 12,814	$ 251	$ 39,034	$ 23,856	$ 112	$ 36	$ 1,369	$ 1,879	$ 4
5	**Total Net Income**	$ 734,074	$ 377,668	$ 49,356	$ 751	$ 174,818	$ 97,765	$ 1,411	$ 64	$ 28,074	$ 4,109	$ 58
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,563,824	$ 5,787,882	$ 700,354	$ 10,804	$ 2,418,527	$ 1,287,714	$ 14,480	$ 1,273	$ 181,029	$ 161,174	$ 587
7	**Staff's Proposed Rate Base**	$ 10,587,216	$ 5,800,699	$ 701,905	$ 10,828	$ 2,423,882	$ 1,290,565	$ 14,512	$ 1,275	$ 181,430	$ 161,531	$ 589
8	**Rate of Return (before change)**	5.03%	4.39%	5.22%	4.63%	5.61%	5.74%	8.97%	2.23%	14.75%	1.38%	9.09%
9	**Rate of Return Index (before change)**	1.00	0.87	1.04	0.92	1.12	1.14	1.78	0.44	2.93	0.28	1.81
10	**Rate of Return (after change)**	6.93%	6.51%	7.03%	6.93%	7.21%	7.58%	9.72%	5.03%	15.47%	2.54%	9.81%
11	**Rate of Return Index (after change)**	1.00	0.94	1.01	1.00	1.04	1.09	1.40	0.73	2.23	0.37	1.41
12	**Percent Change in Base Revenue**	7.90%	9.52%	7.56%	8.16%	6.11%	6.12%	3.00%	9.90%	3.00%	9.90%	3.00%
13	**Staff's Proposed EDIT-2 Credit**	$ (168,214)	$ (94,425)	$ (11,399)	$ (183)	$ (36,463)	$ (19,114)	$ (241)	$ (21)	$ (4,802)	$ (1,556)	$ (11)
14	**Percent Change in Revenue with EDIT-2 Credit**	2.89%	3.95%	2.41%	3.60%	1.74%	2.37%	-1.95%	5.44%	-5.06%	3.62%	-2.54%

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Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 3

Base Case - No Revenue Change -SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,355,753	$ 1,696,487	$ 221,781	$ 4,003	$ 835,355	$ 508,480	$ 4,857	$ 471	$ 59,402	$ 24,726	$ 189
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 531,135	$ 251,555	$ 40,266	$ 387	$ 146,356	$ 65,585	$ 1,210	$ 11	$ 24,290	$ 1,434	$ 43
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 531,135	$ 251,555	$ 40,266	$ 387	$ 146,356	$ 65,585	$ 1,210	$ 11	$ 24,290	$ 1,434	$ 43
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,563,824	$ 5,851,110	$ 666,232	$ 11,825	$ 2,300,647	$ 1,344,302	$ 15,226	$ 1,434	$ 203,346	$ 169,023	$ 680
7	**Staff's Proposed Rate Base**	$ 10,587,216	$ 5,864,066	$ 667,707	$ 11,851	$ 2,305,741	$ 1,347,279	$ 15,260	$ 1,437	$ 203,796	$ 169,398	$ 681
8	**Rate of Return (before change)**	5.03%	4.30%	6.04%	3.27%	6.36%	4.88%	7.95%	0.74%	11.94%	0.85%	6.37%
9	**Rate of Return Index (before change)**	1.00	0.86	1.20	0.65	1.27	0.97	1.58	0.15	2.38	0.17	1.27
10	**Rate of Return (after change)**	5.03%	4.30%	6.04%	3.27%	6.36%	4.88%	7.95%	0.74%	11.94%	0.85%	6.37%
11	**Rate of Return Index (after change)**	1.00	0.86	1.20	0.65	1.26	0.97	1.58	0.15	2.38	0.17	1.27
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 3

Equal Rates of Return for all Classes - SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	Total Revenues W/ Staff Adj. @ Pres. Rates	$ 3,355,753	$ 1,696,487	$ 221,781	$ 4,003	$ 835,355	$ 508,480	$ 4,857	$ 471	$ 59,402	$ 24,726	$ 189
2	Proposed Revenue Change	$ 265,117	$ 202,536	$ 7,878	$ 568	$ 17,656	$ 36,357	$ (198)	$ 116	$ (13,272)	$ 13,471	$ 5
3	Net Income Before Increase	$ 531,135	$ 251,555	$ 40,266	$ 387	$ 146,356	$ 65,585	$ 1,210	$ 11	$ 24,290	$ 1,434	$ 43
4	Change in Net Income	$ 202,939	$ 155,035	$ 6,030	$ 434	$ 13,515	$ 27,830	$ (152)	$ 89	$ (10,159)	$ 10,312	$ 4
5	Total Net Income	$ 734,074	$ 406,590	$ 46,296	$ 822	$ 159,871	$ 93,415	$ 1,058	$ 100	$ 14,130	$ 11,745	$ 47
6	Rate Base W/ Staff Adj. @ Pres. Rates	$ 10,563,824	$ 5,851,110	$ 666,232	$ 11,825	$ 2,300,647	$ 1,344,302	$ 15,226	$ 1,434	$ 203,346	$ 169,023	$ 680
7	Staff's Proposed Rate Base	$ 10,587,216	$ 5,864,066	$ 667,707	$ 11,851	$ 2,305,741	$ 1,347,279	$ 15,260	$ 1,437	$ 203,796	$ 169,398	$ 681
8	Rate of Return (before change)	5.03%	4.30%	6.04%	3.27%	6.36%	4.88%	7.95%	0.74%	11.94%	0.85%	6.37%
9	Rate of Return Index (before change)	1.00	0.86	1.20	0.65	1.27	0.97	1.58	0.15	2.38	0.17	1.27
10	Rate of Return (after change)	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
11	Rate of Return Index (after change)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	Percent Change in Base Revenue	7.90%	11.94%	3.55%	14.18%	2.11%	7.15%	-4.08%	24.71%	-22.34%	54.48%	2.73%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 3

Class Revenue Changes Equal to NC Retail Change - SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,355,753	$ 1,696,487	$ 221,781	$ 4,003	$ 835,355	$ 508,480	$ 4,857	$ 471	$ 59,402	$ 24,726	$ 189
2	**Proposed Revenue Change**	$ 265,117	$ 202,536	$ 7,878	$ 568	$ 17,656	$ 36,357	$ (198)	$ 116	$ (13,272)	$ 13,471	$ 5
3	**Net Income Before Increase**	$ 531,135	$ 251,555	$ 40,266	$ 387	$ 146,356	$ 65,585	$ 1,210	$ 11	$ 24,290	$ 1,434	$ 43
4	**Change in Net Income**	$ 202,939	$ 155,035	$ 6,030	$ 434	$ 13,515	$ 27,830	$ (152)	$ 89	$ (10,159)	$ 10,312	$ 4
5	**Total Net Income**	$ 734,074	$ 406,590	$ 46,296	$ 822	$ 159,871	$ 93,415	$ 1,058	$ 100	$ 14,130	$ 11,745	$ 47
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,563,824	$ 5,851,110	$ 666,232	$ 11,825	$ 2,300,647	$ 1,344,302	$ 15,226	$ 1,434	$ 203,346	$ 169,023	$ 680
7	**Staff's Proposed Rate Base**	$ 10,587,216	$ 5,864,066	$ 667,707	$ 11,851	$ 2,305,741	$ 1,347,279	$ 15,260	$ 1,437	$ 203,796	$ 169,398	$ 681
8	**Rate of Return (before change)**	5.03%	4.30%	6.04%	3.27%	6.36%	4.88%	7.95%	0.74%	11.94%	0.85%	6.37%
9	**Rate of Return Index (before change)**	1.00	0.86	1.20	0.65	1.27	0.97	1.58	0.15	2.38	0.17	1.27
10	**Rate of Return (after change)**	6.93%	6.04%	8.04%	5.31%	8.54%	7.15%	9.85%	2.72%	13.68%	1.73%	8.03%
11	**Rate of Return Index (after change)**	1.00	0.87	1.16	0.77	1.23	1.03	1.42	0.39	1.97	0.25	1.16
12	**Percent Change in Base Revenue**	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%

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Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 3
Page 4 of 4

Public Staff Recommended Revenue Distribution- SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,355,753	$ 1,696,487	$ 221,781	$ 4,003	$ 835,355	$ 508,480	$ 4,857	$ 471	$ 59,402	$ 24,726	$ 189
2	**Proposed Revenue Change**	$ 265,117	$ 167,952	$ 13,424	$ 396	$ 44,274	$ 34,051	$ 194	$ 47	$ 2,376	$ 2,448	$ 10
3	**Net Income Before Increase**	$ 531,135	$ 251,555	$ 40,266	$ 387	$ 146,356	$ 65,585	$ 1,210	$ 11	$ 24,290	$ 1,434	$ 43
4	**Change in Net Income**	$ 202,939	$ 128,563	$ 10,275	$ 303	$ 33,890	$ 26,065	$ 149	$ 36	$ 1,819	$ 1,874	$ 8
5	**Total Net Income**	$ 734,074	$ 380,117	$ 50,541	$ 691	$ 180,246	$ 91,650	$ 1,358	$ 46	$ 26,108	$ 3,307	$ 51
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,563,824	$ 5,851,110	$ 666,232	$ 11,825	$ 2,300,647	$ 1,344,302	$ 15,226	$ 1,434	$ 203,346	$ 169,023	$ 680
7	**Staff's Proposed Rate Base**	$ 10,587,216	$ 5,864,066	$ 667,707	$ 11,851	$ 2,305,741	$ 1,347,279	$ 15,260	$ 1,437	$ 203,796	$ 169,398	$ 681
8	**Rate of Return (before change)**	5.03%	4.30%	6.04%	3.27%	6.36%	4.88%	7.95%	0.74%	11.94%	0.85%	6.37%
9	**Rate of Return Index (before change)**	1.00	0.86	1.20	0.65	1.27	0.97	1.58	0.15	2.38	0.17	1.27
10	**Rate of Return (after change)**	6.93%	6.48%	7.57%	5.83%	7.82%	6.80%	8.90%	3.22%	12.81%	1.95%	7.50%
11	**Rate of Return Index (after change)**	1.00	0.93	1.09	0.84	1.13	0.98	1.28	0.46	1.85	0.28	1.08
12	**Percent Change in Base Revenue**	7.90%	9.90%	6.05%	9.90%	5.30%	6.70%	4.00%	9.90%	4.00%	9.90%	5.37%
13	**Staff's Proposed EDIT-2 Credit**	$ (168,214)	$ (94,425)	$ (11,399)	$ (183)	$ (36,463)	$ (19,114)	$ (241)	$ (21)	$ (4,802)	$ (1,556)	$ (11)
14	**Percent Change in Revenue with EDIT-2 Credit**	2.89%	4.33%	0.91%	5.33%	0.94%	2.94%	-0.95%	5.43%	-4.08%	3.61%	-0.20%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 4

Base Case - No Revenue Change -WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,355,753	$ 1,688,921	$ 221,561	$ 4,011	$ 838,767	$ 512,619	$ 4,879	$ 472	$ 59,568	$ 24,766	$ 190
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 531,135	$ 158,238	$ 37,541	$ 478	$ 188,319	$ 116,510	$ 1,485	$ 25	$ 26,424	$ 2,062	$ 52
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 531,135	$ 158,238	$ 37,541	$ 478	$ 188,319	$ 116,510	$ 1,485	$ 25	$ 26,424	$ 2,062	$ 52
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,563,824	$ 6,747,789	$ 690,592	$ 10,994	$ 1,892,561	$ 858,202	$ 12,652	$ 1,302	$ 184,696	$ 164,436	$ 599
7	**Staff's Proposed Rate Base**	$ 10,587,216	$ 6,762,731	$ 692,122	$ 11,019	$ 1,896,752	$ 860,102	$ 12,680	$ 1,305	$ 185,105	$ 164,800	$ 601
8	**Rate of Return (before change)**	5.03%	2.35%	5.44%	4.35%	9.95%	13.58%	11.74%	1.91%	14.31%	1.25%	8.74%
9	**Rate of Return Index (before change)**	1.00	0.47	1.08	0.86	1.98	2.70	2.33	0.38	2.85	0.25	1.74
10	**Rate of Return (after change)**	5.03%	2.35%	5.44%	4.35%	9.95%	13.58%	11.74%	1.91%	14.31%	1.25%	8.74%
11	**Rate of Return Index (after change)**	1.00	0.47	1.08	0.86	1.98	2.70	2.34	0.38	2.85	0.25	1.74
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 4

Equal Rates of Return for all Classes - WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	Total Revenues W/ Staff Adj. @ Pres. Rates	$ 3,355,753	$ 1,688,921	$ 221,561	$ 4,011	$ 838,767	$ 512,619	$ 4,879	$ 472	$ 59,568	$ 24,766	$ 190
2	Proposed Revenue Change	$ 265,117	$ 405,844	$ 13,649	$ 374	$ (74,210)	$ (74,300)	$ (792)	$ 86	$ (17,754)	$ 12,233	$ (14)
3	Net Income Before Increase	$ 531,135	$ 158,238	$ 37,541	$ 478	$ 188,319	$ 116,510	$ 1,485	$ 25	$ 26,424	$ 2,062	$ 52
4	Change in Net Income	$ 202,939	$ 310,662	$ 10,448	$ 286	$ (56,806)	$ (56,874)	$ (606)	$ 66	$ (13,590)	$ 9,364	$ (11)
5	Total Net Income	$ 734,074	$ 468,900	$ 47,989	$ 764	$ 131,513	$ 59,636	$ 879	$ 90	$ 12,834	$ 11,427	$ 42
6	Rate Base W/ Staff Adj. @ Pres. Rates	$ 10,563,824	$ 6,747,789	$ 690,592	$ 10,994	$ 1,892,561	$ 858,202	$ 12,652	$ 1,302	$ 184,696	$ 164,436	$ 599
7	Staff's Proposed Rate Base	$ 10,587,216	$ 6,762,731	$ 692,122	$ 11,019	$ 1,896,752	$ 860,102	$ 12,680	$ 1,305	$ 185,105	$ 164,800	$ 601
8	Rate of Return (before change)	5.03%	2.35%	5.44%	4.35%	9.95%	13.58%	11.74%	1.91%	14.31%	1.25%	8.74%
9	Rate of Return Index (before change)	1.00	0.47	1.08	0.86	1.98	2.70	2.33	0.38	2.85	0.25	1.74
10	Rate of Return (after change)	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
11	Rate of Return Index (after change)	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	Percent Change in Base Revenue	7.90%	24.03%	6.16%	9.32%	-8.85%	-14.49%	-16.23%	18.13%	-29.80%	49.40%	-7.36%

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Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

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Floyd Second Supplemental Exhibit 4

Class Revenue Changes Equal to NC Retail Change - WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,355,753	$ 1,688,921	$ 221,561	$ 4,011	$ 838,767	$ 512,619	$ 4,879	$ 472	$ 59,568	$ 24,766	$ 190
2	**Proposed Revenue Change**	$ 265,117	$ 405,844	$ 13,649	$ 374	$ (74,210)	$ (74,300)	$ (792)	$ 86	$ (17,754)	$ 12,233	$ (14)
3	**Net Income Before Increase**	$ 531,135	$ 158,238	$ 37,541	$ 478	$ 188,319	$ 116,510	$ 1,485	$ 25	$ 26,424	$ 2,062	$ 52
4	**Change in Net Income**	$ 202,939	$ 310,662	$ 10,448	$ 286	$ (56,806)	$ (56,874)	$ (606)	$ 66	$ (13,590)	$ 9,364	$ (11)
5	**Total Net Income**	$ 734,074	$ 468,900	$ 47,989	$ 764	$ 131,513	$ 59,636	$ 879	$ 90	$ 12,834	$ 11,427	$ 42
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,563,824	$ 6,747,789	$ 690,592	$ 10,994	$ 1,892,561	$ 858,202	$ 12,652	$ 1,302	$ 184,696	$ 164,436	$ 599
7	**Staff's Proposed Rate Base**	$ 10,587,216	$ 6,762,731	$ 692,122	$ 11,019	$ 1,896,752	$ 860,102	$ 12,680	$ 1,305	$ 185,105	$ 164,800	$ 601
8	**Rate of Return (before change)**	5.03%	2.35%	5.44%	4.35%	9.95%	13.58%	11.74%	1.91%	14.31%	1.25%	8.74%
9	**Rate of Return Index (before change)**	1.00	0.47	1.08	0.86	1.98	2.70	2.33	0.38	2.85	0.25	1.74
10	**Rate of Return (after change)**	6.93%	3.85%	7.36%	6.54%	12.60%	17.15%	14.04%	4.10%	16.22%	2.16%	10.63%
11	**Rate of Return Index (after change)**	1.00	0.56	1.06	0.94	1.82	2.47	2.02	0.59	2.34	0.31	1.53
12	**Percent Change in Base Revenue**	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%

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Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd Second Supplemental Exhibit 4

Public Staff Recommended Revenue Distribution- WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,355,753	$ 1,688,921	$ 221,561	$ 4,011	$ 838,767	$ 512,619	$ 4,879	$ 472	$ 59,568	$ 24,766	$ 190
2	**Proposed Revenue Change**	$ 265,117	$ 167,203	$ 15,509	$ 389	$ 50,326	$ 25,934	$ 268	$ 47	$ 2,978	$ 2,452	$ 9
3	**Net Income Before Increase**	$ 531,135	$ 158,238	$ 37,541	$ 478	$ 188,319	$ 116,510	$ 1,485	$ 25	$ 26,424	$ 2,062	$ 52
4	**Change in Net Income**	$ 202,939	$ 127,989	$ 11,872	$ 298	$ 38,523	$ 19,852	$ 205	$ 36	$ 2,280	$ 1,877	$ 7
5	**Total Net Income**	$ 734,074	$ 286,227	$ 49,413	$ 776	$ 226,842	$ 136,362	$ 1,691	$ 61	$ 28,704	$ 3,939	$ 60
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,563,824	$ 6,747,789	$ 690,592	$ 10,994	$ 1,892,561	$ 858,202	$ 12,652	$ 1,302	$ 184,696	$ 164,436	$ 599
7	**Staff's Proposed Rate Base**	$ 10,587,216	$ 6,762,731	$ 692,122	$ 11,019	$ 1,896,752	$ 860,102	$ 12,680	$ 1,305	$ 185,105	$ 164,800	$ 601
8	**Rate of Return (before change)**	5.03%	2.35%	5.44%	4.35%	9.95%	13.58%	11.74%	1.91%	14.31%	1.25%	8.74%
9	**Rate of Return Index (before change)**	1.00	0.47	1.08	0.86	1.98	2.70	2.33	0.38	2.85	0.25	1.74
10	**Rate of Return (after change)**	6.93%	4.23%	7.14%	7.04%	11.96%	15.85%	13.33%	4.65%	15.51%	2.39%	9.93%
11	**Rate of Return Index (after change)**	1.00	0.61	1.03	1.02	1.72	2.29	1.92	0.67	2.24	0.34	1.43
12	**Percent Change in Base Revenue**	7.90%	9.90%	7.00%	9.70%	6.00%	5.06%	5.50%	9.90%	5.00%	9.90%	5.00%
13	**Staff's Proposed EDIT-2 Credit**	$ (168,214)	$ (94,425)	$ (11,399)	$ (183)	$ (36,463)	$ (19,114)	$ (241)	$ (21)	$ (4,802)	$ (1,556)	$ (11)
14	**Percent Change in Revenue with EDIT-2 Credit**	2.89%	4.31%	1.86%	5.13%	1.65%	1.33%	0.57%	5.44%	-3.06%	3.62%	-0.55%

Duke Energy Progress, LLC

Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit No. 1
Page 1 of 3

Comparison of Rates of Return, Indices, and % Base Revenue

Based on SCP Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.56%		1.00	3.84%	-3.13%
Residential	6.26%		0.95	5.84%	-1.90%
Small General Service	6.56%		1.00	3.10%	-4.06%
Small General Service - CLR	6.56%		1.00	4.30%	-2.05%
Medium General Service	6.67%		1.02	1.59%	-4.48%
Large General Service	6.91%		1.05	1.44%	-3.78%
Seasonal & Intermittent	9.83%	**	1.50	1.01%	-5.86%
Traffic Signal	4.61%	**	0.70	5.84%	-0.36%
Outdoor Lighting - ALS	15.54%	**	2.37	0.95%	-9.50%
Outdoor Lighting - SLS	2.37%	**	0.36	5.84%	-4.69%
Sports Field Lighting	9.91%	**	1.51	1.01%	-6.69%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended +/- 10% band of reasonableness.

Duke Energy Progress, LLC

Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit No. 1

Comparison of Rates of Return, Indices, and % Base Revenue

Based on SWPA Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.56%		1.00	3.84%	-3.13%
Residential	6.13%		0.93	5.75%	-1.99%
Small General Service	6.99%		1.07	1.32%	-5.83%
Small General Service - CLR	5.42%	**	0.83	5.74%	-0.62%
Medium General Service	7.33%	**	1.12	1.09%	-4.98%
Large General Service	6.56%		1.00	3.33%	-1.90%
Seasonal & Intermittent	8.77%	**	1.34	1.03%	-5.86%
Traffic Signal	2.85%	**	0.44	5.84%	-0.38%
Outdoor Lighting - ALS	12.63%	**	1.93	0.88%	-9.61%
Outdoor Lighting - SLS	1.79%	**	0.27	5.84%	-4.72%
Sports Field Lighting	7.14%		1.09	1.25%	-6.49%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended +/- 10% band of reasonableness.

Duke Energy Progress, LLC

Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit No. 1

Comparison of Rates of Return, Indices, and % Base Revenue

Based on WCP Cost-of Service Methodology

With Public Staff Adjustments

	Rate of Return *		Rate of Return Index	% Base Revenue Change	% Revenue Change with EDIT-2 Credit
NC Retail	6.56%		1.00	3.84%	-3.13%
Residential	3.95%	**	0.60	5.84%	-1.93%
Small General Service	6.74%		1.03	2.89%	-4.27%
Small General Service - CLR	6.57%		1.00	5.45%	-0.90%
Medium General Service	11.33%	**	1.73	1.70%	-4.34%
Large General Service	15.26%	**	2.33	1.33%	-3.85%
Seasonal & Intermittent	12.86%	**	1.96	1.49%	-5.37%
Traffic Signal	4.24%	**	0.65	5.84%	-0.37%
Outdoor Lighting - ALS	15.20%	**	2.32	1.42%	-9.03%
Outdoor Lighting - SLS	2.22%	**	0.34	5.84%	-4.71%
Sports Field Lighting	9.74%	**	1.49	1.82%	-5.89%

* These rates of return are after Public Staff adjustments.

** These rate classes are outside the Public Staff's recommended +/- 10% band of reasonableness.

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Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 2

Base Case - No Revenue Change -SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,895	$ 222,039	$ 4,022	$ 836,620	$ 510,431	$ 4,877	$ 474	$ 59,747	$ 24,858	$ 191
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 586,335	$ 282,232	$ 40,160	$ 568	$ 149,450	$ 82,395	$ 1,371	$ 37	$ 27,400	$ 2,666	$ 56
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 586,335	$ 282,232	$ 40,160	$ 568	$ 149,450	$ 82,395	$ 1,371	$ 37	$ 27,400	$ 2,666	$ 56
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,720,530	$ 692,204	$ 10,679	$ 2,390,383	$ 1,272,729	$ 14,311	$ 1,258	$ 178,922	$ 159,299	$ 581
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,726,752	$ 692,957	$ 10,690	$ 2,392,983	$ 1,274,113	$ 14,327	$ 1,259	$ 179,117	$ 159,472	$ 581
8	**Rate of Return (before change)**	5.62%	4.93%	5.80%	5.32%	6.25%	6.47%	9.58%	2.94%	15.31%	1.67%	9.67%
9	**Rate of Return Index (before change)**	1.00	0.88	1.03	0.95	1.11	1.15	1.71	0.52	2.73	0.30	1.72
10	**Rate of Return (after change)**	5.61%	4.93%	5.80%	5.32%	6.25%	6.47%	9.57%	2.93%	15.30%	1.67%	9.66%
11	**Rate of Return Index (after change)**	1.00	0.88	1.03	0.95	1.11	1.15	1.71	0.52	2.73	0.30	1.72
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 2

Equal Rates of Return for all Classes - SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,895	$ 222,039	$ 4,022	$ 836,620	$ 510,431	$ 4,877	$ 474	$ 59,747	$ 24,858	$ 191
2	**Proposed Revenue Change**	$ 129,085	$ 121,699	$ 6,875	$ 173	$ 9,681	$ 1,467	$ (564)	$ 60	$ (20,457)	$ 10,174	$ (24)
3	**Net Income Before Increase**	$ 586,335	$ 282,232	$ 40,160	$ 568	$ 149,450	$ 82,395	$ 1,371	$ 37	$ 27,400	$ 2,666	$ 56
4	**Change in Net Income**	$ 98,811	$ 93,157	$ 5,263	$ 132	$ 7,411	$ 1,123	$ (431)	$ 46	$ (15,659)	$ 7,788	$ (18)
5	**Total Net Income**	$ 685,146	$ 375,389	$ 45,423	$ 701	$ 156,860	$ 83,518	$ 939	$ 83	$ 11,741	$ 10,453	$ 38
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,720,530	$ 692,204	$ 10,679	$ 2,390,383	$ 1,272,729	$ 14,311	$ 1,258	$ 178,922	$ 159,299	$ 581
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,726,752	$ 692,957	$ 10,690	$ 2,392,983	$ 1,274,113	$ 14,327	$ 1,259	$ 179,117	$ 159,472	$ 581
8	**Rate of Return (before change)**	5.62%	4.93%	5.80%	5.32%	6.25%	6.47%	9.58%	2.94%	15.31%	1.67%	9.67%
9	**Rate of Return Index (before change)**	1.00	0.88	1.03	0.95	1.11	1.15	1.71	0.52	2.73	0.30	1.72
10	**Rate of Return (after change)**	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Base Revenue**	3.84%	7.15%	3.10%	4.30%	1.16%	0.29%	-11.56%	12.58%	-34.24%	40.93%	-12.36%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 2
Page 3 of 4

Class Revenue Changes Equal to NC Retail Change - SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,895	$ 222,039	$ 4,022	$ 836,620	$ 510,431	$ 4,877	$ 474	$ 59,747	$ 24,858	$ 191
2	**Proposed Revenue Change**	$ 129,085	$ 121,699	$ 6,875	$ 173	$ 9,681	$ 1,467	$ (564)	$ 60	$ (20,457)	$ 10,174	$ (24)
3	**Net Income Before Increase**	$ 586,335	$ 282,232	$ 40,160	$ 568	$ 149,450	$ 82,395	$ 1,371	$ 37	$ 27,400	$ 2,666	$ 56
4	**Change in Net Income**	$ 98,811	$ 93,157	$ 5,263	$ 132	$ 7,411	$ 1,123	$ (431)	$ 46	$ (15,659)	$ 7,788	$ (18)
5	**Total Net Income**	$ 685,146	$ 375,389	$ 45,423	$ 701	$ 156,860	$ 83,518	$ 939	$ 83	$ 11,741	$ 10,453	$ 38
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,720,530	$ 692,204	$ 10,679	$ 2,390,383	$ 1,272,729	$ 14,311	$ 1,258	$ 178,922	$ 159,299	$ 581
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,726,752	$ 692,957	$ 10,690	$ 2,392,983	$ 1,274,113	$ 14,327	$ 1,259	$ 179,117	$ 159,472	$ 581
8	**Rate of Return (before change)**	5.62%	4.93%	5.80%	5.32%	6.25%	6.47%	9.58%	2.94%	15.31%	1.67%	9.67%
9	**Rate of Return Index (before change)**	1.00	0.88	1.03	0.95	1.11	1.15	1.71	0.52	2.73	0.30	1.72
10	**Rate of Return (after change)**	6.56%	5.80%	6.74%	6.42%	7.27%	7.64%	10.57%	4.04%	16.28%	2.13%	10.62%
11	**Rate of Return Index (after change)**	1.00	0.88	1.03	0.98	1.11	1.17	1.61	0.62	2.48	0.32	1.62
12	**Percent Change in Base Revenue**	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 2

Public Staff Recommended Revenue Distribution- SCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,895	$ 222,039	$ 4,022	$ 836,620	$ 510,431	$ 4,877	$ 474	$ 59,747	$ 24,858	$ 191
2	**Proposed Revenue Change**	$ 129,085	$ 99,258	$ 6,875	$ 173	$ 13,332	$ 7,348	$ 49	$ 28	$ 568	$ 1,452	$ 2
3	**Net Income Before Increase**	$ 586,335	$ 282,232	$ 40,160	$ 568	$ 149,450	$ 82,395	$ 1,371	$ 37	$ 27,400	$ 2,666	$ 56
4	**Change in Net Income**	$ 98,811	$ 75,979	$ 5,263	$ 132	$ 10,205	$ 5,625	$ 38	$ 21	$ 435	$ 1,111	$ 1
5	**Total Net Income**	$ 685,146	$ 358,211	$ 45,423	$ 701	$ 159,655	$ 88,020	$ 1,408	$ 58	$ 27,835	$ 3,777	$ 58
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,720,530	$ 692,204	$ 10,679	$ 2,390,383	$ 1,272,729	$ 14,311	$ 1,258	$ 178,922	$ 159,299	$ 581
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,726,752	$ 692,957	$ 10,690	$ 2,392,983	$ 1,274,113	$ 14,327	$ 1,259	$ 179,117	$ 159,472	$ 581
8	**Rate of Return (before change)**	5.62%	4.93%	5.80%	5.32%	6.25%	6.47%	9.58%	2.94%	15.31%	1.67%	9.67%
9	**Rate of Return Index (before change)**	1.00	0.88	1.03	0.95	1.11	1.15	1.71	0.52	2.73	0.30	1.72
10	**Rate of Return (after change)**	6.56%	6.26%	6.56%	6.56%	6.67%	6.91%	9.83%	4.61%	15.54%	2.37%	9.91%
11	**Rate of Return Index (after change)**	1.00	0.95	1.00	1.00	1.02	1.05	1.50	0.70	2.37	0.36	1.51
12	**Percent Change in Base Revenue**	3.84%	5.84%	3.10%	4.30%	1.59%	1.44%	1.01%	5.84%	0.95%	5.84%	1.01%
13	**Staff's Proposed EDIT-2 Credit**	$ (234,435)	$ (131,597)	$ (15,887)	$ (255)	$ (50,818)	$ (26,638)	$ (335)	$ (29)	$ (6,243)	$ (2,617)	$ (15)
14	**Percent Change in Revenue with EDIT-2 Credit**	-3.13%	-1.90%	-4.06%	-2.05%	-4.48%	-3.78%	-5.86%	-0.36%	-9.50%	-4.69%	-6.69%

I/A

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 3
Page 1 of 4

Base Case - No Revenue Change -SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,734	$ 222,337	$ 4,013	$ 837,447	$ 509,753	$ 4,869	$ 472	$ 59,550	$ 24,788	$ 190
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 586,335	$ 279,742	$ 43,828	$ 457	$ 159,862	$ 74,196	$ 1,282	$ 19	$ 25,020	$ 1,881	$ 46
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 586,335	$ 279,742	$ 43,828	$ 457	$ 159,862	$ 74,196	$ 1,282	$ 19	$ 25,020	$ 1,881	$ 46
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,783,022	$ 658,479	$ 11,687	$ 2,273,875	$ 1,328,659	$ 15,049	$ 1,417	$ 200,980	$ 167,056	$ 672
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,789,312	$ 659,195	$ 11,700	$ 2,276,348	$ 1,330,104	$ 15,065	$ 1,419	$ 201,198	$ 167,238	$ 673
8	**Rate of Return (before change)**	5.62%	4.84%	6.66%	3.91%	7.03%	5.58%	8.52%	1.37%	12.45%	1.13%	6.87%
9	**Rate of Return Index (before change)**	1.00	0.86	1.19	0.70	1.25	0.99	1.52	0.24	2.22	0.20	1.22
10	**Rate of Return (after change)**	5.61%	4.83%	6.65%	3.91%	7.02%	5.58%	8.51%	1.36%	12.44%	1.12%	6.87%
11	**Rate of Return Index (after change)**	1.00	0.86	1.19	0.70	1.25	0.99	1.52	0.24	2.22	0.20	1.22
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 3

Equal Rates of Return for all Classes - SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,734	$ 222,337	$ 4,013	$ 837,447	$ 509,753	$ 4,869	$ 472	$ 59,550	$ 24,788	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 130,309	$ (807)	$ 405	$ (13,910)	$ 16,973	$ (385)	$ 96	$ (15,457)	$ 11,863	$ (3)
3	**Net Income Before Increase**	$ 586,335	$ 279,742	$ 43,828	$ 457	$ 159,862	$ 74,196	$ 1,282	$ 19	$ 25,020	$ 1,881	$ 46
4	**Change in Net Income**	$ 98,811	$ 99,748	$ (618)	$ 310	$ (10,648)	$ 12,993	$ (295)	$ 74	$ (11,832)	$ 9,081	$ (2)
5	**Total Net Income**	$ 685,146	$ 379,490	$ 43,210	$ 767	$ 149,215	$ 87,188	$ 988	$ 93	$ 13,189	$ 10,962	$ 44
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,783,022	$ 658,479	$ 11,687	$ 2,273,875	$ 1,328,659	$ 15,049	$ 1,417	$ 200,980	$ 167,056	$ 672
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,789,312	$ 659,195	$ 11,700	$ 2,276,348	$ 1,330,104	$ 15,065	$ 1,419	$ 201,198	$ 167,238	$ 673
8	**Rate of Return (before change)**	5.62%	4.84%	6.66%	3.91%	7.03%	5.58%	8.52%	1.37%	12.45%	1.13%	6.87%
9	**Rate of Return Index (before change)**	1.00	0.86	1.19	0.70	1.25	0.99	1.52	0.24	2.22	0.20	1.22
10	**Rate of Return (after change)**	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Base Revenue**	3.84%	7.66%	-0.36%	10.08%	-1.66%	3.33%	-7.91%	20.38%	-25.96%	47.86%	-1.44%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 3
Page 3 of 4

Class Revenue Changes Equal to NC Retail Change - SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,734	$ 222,337	$ 4,013	$ 837,447	$ 509,753	$ 4,869	$ 472	$ 59,550	$ 24,788	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 130,309	$ (807)	$ 405	$ (13,910)	$ 16,973	$ (385)	$ 96	$ (15,457)	$ 11,863	$ (3)
3	**Net Income Before Increase**	$ 586,335	$ 279,742	$ 43,828	$ 457	$ 159,862	$ 74,196	$ 1,282	$ 19	$ 25,020	$ 1,881	$ 46
4	**Change in Net Income**	$ 98,811	$ 99,748	$ (618)	$ 310	$ (10,648)	$ 12,993	$ (295)	$ 74	$ (11,832)	$ 9,081	$ (2)
5	**Total Net Income**	$ 685,146	$ 379,490	$ 43,210	$ 767	$ 149,215	$ 87,188	$ 988	$ 93	$ 13,189	$ 10,962	$ 44
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,783,022	$ 658,479	$ 11,687	$ 2,273,875	$ 1,328,659	$ 15,049	$ 1,417	$ 200,980	$ 167,056	$ 672
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,789,312	$ 659,195	$ 11,700	$ 2,276,348	$ 1,330,104	$ 15,065	$ 1,419	$ 201,198	$ 167,238	$ 673
8	**Rate of Return (before change)**	5.62%	4.84%	6.66%	3.91%	7.03%	5.58%	8.52%	1.37%	12.45%	1.13%	6.87%
9	**Rate of Return Index (before change)**	1.00	0.86	1.19	0.70	1.25	0.99	1.52	0.24	2.22	0.20	1.22
10	**Rate of Return (after change)**	6.56%	5.69%	7.64%	4.92%	8.10%	6.70%	9.46%	2.34%	13.30%	1.56%	7.69%
11	**Rate of Return Index (after change)**	1.00	0.87	1.17	0.75	1.24	1.02	1.44	0.36	2.03	0.24	1.17
12	**Percent Change in Base Revenue**	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%

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Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 3

Public Staff Recommended Revenue Distribution- SWPA

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,700,734	$ 222,337	$ 4,013	$ 837,447	$ 509,753	$ 4,869	$ 472	$ 59,550	$ 24,788	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 97,791	$ 2,930	$ 231	$ 9,109	$ 16,973	$ 50	$ 28	$ 524	$ 1,448	$ 2
3	**Net Income Before Increase**	$ 586,335	$ 279,742	$ 43,828	$ 457	$ 159,862	$ 74,196	$ 1,282	$ 19	$ 25,020	$ 1,881	$ 46
4	**Change in Net Income**	$ 98,811	$ 74,856	$ 2,243	$ 176	$ 6,973	$ 12,993	$ 38	$ 21	$ 401	$ 1,108	$ 2
5	**Total Net Income**	$ 685,146	$ 354,598	$ 46,071	$ 634	$ 166,835	$ 87,188	$ 1,321	$ 40	$ 25,421	$ 2,990	$ 48
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 5,783,022	$ 658,479	$ 11,687	$ 2,273,875	$ 1,328,659	$ 15,049	$ 1,417	$ 200,980	$ 167,056	$ 672
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 5,789,312	$ 659,195	$ 11,700	$ 2,276,348	$ 1,330,104	$ 15,065	$ 1,419	$ 201,198	$ 167,238	$ 673
8	**Rate of Return (before change)**	5.62%	4.84%	6.66%	3.91%	7.03%	5.58%	8.52%	1.37%	12.45%	1.13%	6.87%
9	**Rate of Return Index (before change)**	1.00	0.86	1.19	0.70	1.25	0.99	1.52	0.24	2.22	0.20	1.22
10	**Rate of Return (after change)**	6.56%	6.13%	6.99%	5.42%	7.33%	6.56%	8.77%	2.85%	12.63%	1.79%	7.14%
11	**Rate of Return Index (after change)**	1.00	0.93	1.07	0.83	1.12	1.00	1.34	0.44	1.93	0.27	1.09
12	**Percent Change in Base Revenue**	3.84%	5.75%	1.32%	5.74%	1.09%	3.33%	1.03%	5.84%	0.88%	5.84%	1.25%
13	**Staff's Proposed EDIT-2 Credit**	$ (234,435)	$ (131,597)	$ (15,887)	$ (255)	$ (50,818)	$ (26,638)	$ (335)	$ (29)	$ (6,243)	$ (2,617)	$ (15)
14	**Percent Change in Revenue with EDIT-2 Credit**	-3.13%	-1.99%	-5.83%	-0.62%	-4.98%	-1.90%	-5.86%	-0.38%	-9.61%	-4.72%	-6.49%

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Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 4
Page 1 of 4

Base Case - No Revenue Change -WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,693,149	$ 222,116	$ 4,021	$ 840,866	$ 513,902	$ 4,891	$ 473	$ 59,717	$ 24,828	$ 190
2	**Proposed Revenue Change**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Net Income Before Increase**	$ 586,335	$ 187,827	$ 41,145	$ 546	$ 201,196	$ 124,357	$ 1,554	$ 34	$ 27,122	$ 2,500	$ 55
4	**Change in Net Income**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	**Total Net Income**	$ 586,335	$ 187,827	$ 41,145	$ 546	$ 201,196	$ 124,357	$ 1,554	$ 34	$ 27,122	$ 2,500	$ 55
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 6,669,267	$ 682,556	$ 10,866	$ 1,870,538	$ 848,215	$ 12,505	$ 1,287	$ 182,546	$ 162,523	$ 592
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 6,676,520	$ 683,299	$ 10,878	$ 1,872,572	$ 849,137	$ 12,519	$ 1,288	$ 182,745	$ 162,700	$ 593
8	**Rate of Return (before change)**	5.62%	2.82%	6.03%	5.03%	10.76%	14.66%	12.42%	2.60%	14.86%	1.54%	9.30%
9	**Rate of Return Index (before change)**	1.00	0.50	1.07	0.90	1.92	2.61	2.21	0.46	2.65	0.27	1.66
10	**Rate of Return (after change)**	5.61%	2.81%	6.02%	5.02%	10.74%	14.65%	12.41%	2.60%	14.84%	1.54%	9.29%
11	**Rate of Return Index (after change)**	1.00	0.50	1.07	0.90	1.92	2.61	2.21	0.46	2.65	0.27	1.66
12	**Percent Change in Base Revenue**	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 4

Equal Rates of Return for all Classes - WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,693,149	$ 222,116	$ 4,021	$ 840,866	$ 513,902	$ 4,891	$ 473	$ 59,717	$ 24,828	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 326,361	$ 4,763	$ 218	$ (102,484)	$ (89,743)	$ (958)	$ 67	$ (19,783)	$ 10,666	$ (21)
3	**Net Income Before Increase**	$ 586,335	$ 187,827	$ 41,145	$ 546	$ 201,196	$ 124,357	$ 1,554	$ 34	$ 27,122	$ 2,500	$ 55
4	**Change in Net Income**	$ 98,811	$ 249,820	$ 3,646	$ 167	$ (78,448)	$ (68,696)	$ (733)	$ 51	$ (15,144)	$ 8,165	$ (16)
5	**Total Net Income**	$ 685,146	$ 437,647	$ 44,790	$ 713	$ 122,747	$ 55,661	$ 821	$ 84	$ 11,979	$ 10,665	$ 39
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 6,669,267	$ 682,556	$ 10,866	$ 1,870,538	$ 848,215	$ 12,505	$ 1,287	$ 182,546	$ 162,523	$ 592
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 6,676,520	$ 683,299	$ 10,878	$ 1,872,572	$ 849,137	$ 12,519	$ 1,288	$ 182,745	$ 162,700	$ 593
8	**Rate of Return (before change)**	5.62%	2.82%	6.03%	5.03%	10.76%	14.66%	12.42%	2.60%	14.86%	1.54%	9.30%
9	**Rate of Return Index (before change)**	1.00	0.50	1.07	0.90	1.92	2.61	2.21	0.46	2.65	0.27	1.66
10	**Rate of Return (after change)**	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%	6.56%
11	**Rate of Return Index (after change)**	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	**Percent Change in Base Revenue**	3.84%	19.28%	2.14%	5.42%	-12.19%	-17.46%	-19.58%	14.05%	-33.13%	42.96%	-11.14%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 4

Class Revenue Changes Equal to NC Retail Change - WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	**Total Revenues W/ Staff Adj. @ Pres. Rates**	$ 3,364,154	$ 1,693,149	$ 222,116	$ 4,021	$ 840,866	$ 513,902	$ 4,891	$ 473	$ 59,717	$ 24,828	$ 190
2	**Proposed Revenue Change**	$ 129,085	$ 326,361	$ 4,763	$ 218	$ (102,484)	$ (89,743)	$ (958)	$ 67	$ (19,783)	$ 10,666	$ (21)
3	**Net Income Before Increase**	$ 586,335	$ 187,827	$ 41,145	$ 546	$ 201,196	$ 124,357	$ 1,554	$ 34	$ 27,122	$ 2,500	$ 55
4	**Change in Net Income**	$ 98,811	$ 249,820	$ 3,646	$ 167	$ (78,448)	$ (68,696)	$ (733)	$ 51	$ (15,144)	$ 8,165	$ (16)
5	**Total Net Income**	$ 685,146	$ 437,647	$ 44,790	$ 713	$ 122,747	$ 55,661	$ 821	$ 84	$ 11,979	$ 10,665	$ 39
6	**Rate Base W/ Staff Adj. @ Pres. Rates**	$ 10,440,896	$ 6,669,267	$ 682,556	$ 10,866	$ 1,870,538	$ 848,215	$ 12,505	$ 1,287	$ 182,546	$ 162,523	$ 592
7	**Staff's Proposed Rate Base**	$ 10,452,251	$ 6,676,520	$ 683,299	$ 10,878	$ 1,872,572	$ 849,137	$ 12,519	$ 1,288	$ 182,745	$ 162,700	$ 593
8	**Rate of Return (before change)**	5.62%	2.82%	6.03%	5.03%	10.76%	14.66%	12.42%	2.60%	14.86%	1.54%	9.30%
9	**Rate of Return Index (before change)**	1.00	0.50	1.07	0.90	1.92	2.61	2.21	0.46	2.65	0.27	1.66
10	**Rate of Return (after change)**	6.56%	3.56%	6.98%	6.11%	12.06%	16.42%	13.56%	3.68%	15.80%	1.98%	10.24%
11	**Rate of Return Index (after change)**	1.00	0.54	1.06	0.93	1.84	2.51	2.07	0.56	2.41	0.30	1.56
12	**Percent Change in Base Revenue**	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%	3.84%

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

Public Staff
Floyd (Corrected) Supplemental Exhibit 4

Public Staff Recommended Revenue Distribution- WCP

		NC Juris	Res	SGS	SGSCLR	MGS	LGS	SI	TSS	ALS	SLS	SFL
1	Total Revenues W/ Staff Adj. @ Pres. Rates	$ 3,364,154	$ 1,693,149	$ 222,116	$ 4,021	$ 840,866	$ 513,902	$ 4,891	$ 473	$ 59,717	$ 24,828	$ 190
2	Proposed Revenue Change	$ 129,085	$ 98,898	$ 6,413	$ 219	$ 14,317	$ 6,837	$ 73	$ 28	$ 849	$ 1,449	$ 3
3	Net Income Before Increase	$ 586,335	$ 187,827	$ 41,145	$ 546	$ 201,196	$ 124,357	$ 1,554	$ 34	$ 27,122	$ 2,500	$ 55
4	Change in Net Income	$ 98,811	$ 75,703	$ 4,909	$ 168	$ 10,959	$ 5,234	$ 56	$ 21	$ 650	$ 1,109	$ 3
5	Total Net Income	$ 685,146	$ 263,530	$ 46,053	$ 714	$ 212,154	$ 129,590	$ 1,609	$ 55	$ 27,772	$ 3,609	$ 58
6	Rate Base W/ Staff Adj. @ Pres. Rates	$ 10,440,896	$ 6,669,267	$ 682,556	$ 10,866	$ 1,870,538	$ 848,215	$ 12,505	$ 1,287	$ 182,546	$ 162,523	$ 592
7	Staff's Proposed Rate Base	$ 10,452,251	$ 6,676,520	$ 683,299	$ 10,878	$ 1,872,572	$ 849,137	$ 12,519	$ 1,288	$ 182,745	$ 162,700	$ 593
8	Rate of Return (before change)	5.62%	2.82%	6.03%	5.03%	10.76%	14.66%	12.42%	2.60%	14.86%	1.54%	9.30%
9	Rate of Return Index (before change)	1.00	0.50	1.07	0.90	1.92	2.61	2.21	0.46	2.65	0.27	1.66
10	Rate of Return (after change)	6.56%	3.95%	6.74%	6.57%	11.33%	15.26%	12.86%	4.24%	15.20%	2.22%	9.74%
11	Rate of Return Index (after change)	1.00	0.60	1.03	1.00	1.73	2.33	1.96	0.65	2.32	0.34	1.49
12	Percent Change in Base Revenue	3.84%	5.84%	2.89%	5.45%	1.70%	1.33%	1.49%	5.84%	1.42%	5.84%	1.82%
13	Staff's Proposed EDIT-2 Credit	$ (234,435)	$ (131,597)	$ (15,887)	$ (255)	$ (50,818)	$ (26,638)	$ (335)	$ (29)	$ (6,243)	$ (2,617)	$ (15)
14	Percent Change in Revenue with EDIT-2 Credit	-3.13%	-1.93%	-4.27%	-0.90%	-4.34%	-3.85%	-5.37%	-0.37%	-9.03%	-4.71%	-5.89%

Docket No. E-2, Sub 1219

Garrett Exhibit 1- all pages confidential

Docket No. E-2, Sub 1219

Garrett Exhibit 2- all pages confidential

Public Staff
Garrett Exhibit 3

Riverbend & Sutton Ash to Brickhaven
Calculation of Development Portion of PPP Ref 1.X.12

Plant	PO Number	Revision	Date	PPP Ref. 1.X.12 $/ton	PS DR 127-3 Unloading $/ton	PS DR 127-3 Placement $/ton	Calculated Development $/ton
Riverbend	1104823	0	1/13/2015	$ 11.36	$ 3.28	$ 0.45	$ 7.63
Riverbend	1104823	10	5/3/2016	$ 11.36	$ 3.28	$ 0.45	$ 7.63
Riverbend	1104823	11/12	5/25/2016	$ 12.04	$ 3.28	$ 0.45	$ 8.31
Riverbend	1412247	0	10/22/2015	$ 11.91	$ 3.28	$ 0.45	$ 8.18
Riverbend	1412247	1	1/29/2016	$ 11.91	$ 3.28	$ 0.45	$ 8.18
Riverbend	2278895	0	4/16/2016	$ 16.65	$ 3.28	$ 0.45	$ 12.92
Riverbend	2278895	1	3/2/2017	$ 16.65	$ 3.28	$ 0.45	$ 12.92
Riverbend	5050808	0	3/2/2017	$ 16.65	$ 3.28	$ 0.45	$ 12.92
Sutton	1107196	0	1/13/2015	$ 11.91	$ 2.27	$ 0.31	$ 9.33
Sutton	1107196	16	10/5/2016	$ 12.04	$ 2.27	$ 0.31	$ 9.46

Public Staff
Garrett Exhibit 4

Public Staff Data Request No. 127-3

Item	Riverbend*	Sutton	
PPP Reference 1.X.12 Phase 1 Alpha - Unloading Cost per ton	$3.28	$2.27	
PPP Reference 1.X.12 Phase 1 Alpha - Development Cost per ton	$9.33	$9.33	
PPP Reference 1.X.12 Phase 1 Alpha - Placement Cost per ton	$0.45	$0.31	
Total cost per ton	**$11.36**	**$11.91**	***Actual Unit Rate for the material sent to Brickhaven at RB Ph I - $13.06***

**For Riverbend, the original contract disposal fee was a composite based on 870k tons to Brickhaven & 130k tons to RCC.*

Item	Riverbend
PPP Reference 1.6 Phase 2 - Unloading Cost per ton	3.28
PPP Reference 1.6 Phase 2 - Development Cost per ton	12.92
PPP Reference 1.6 Phase 2 - Placement Cost per ton	0.45
Total cost per ton	**$16.65**

Item	Riverbend	
PPP Reference 1.9 Phase 2 - Rail Transportation - Covers	$0.00	
PPP Reference 1.9 Phase 2 - Rail Transportation - Cover Management	$0.00	
PPP Reference 1.9 Phase 2 - Rail Transportation - On-Site Rail Operations	$0.00	
PPP Reference 1.9 Phase 2 - Rail Transportation - Rail Car Lease	$0.00	
PPP Reference 1.9 Phase 2 - Rail Transportation - Other ***(Only CSX related Cost)***	$12.48	***PO #2278910 Unit Rate***
Total cost per ton	**$12.75**	

Docket No. E-2, Sub 1219

Garrett Exhibit 5- all pages confidential

Docket No. E-2, Sub 1219

Garrett Exhibit 6- all pages confidential

Public Staff
Garrett Exhibit 7

Development Sequence at Brickhaven

Cell	Subcell	CQA Certification Date*
1	1A	10/15/2015
1	1B	2/29/2016
1	1C	4/27/2016
1	1D	5/31/2016
2	2C	9/20/2016
2	2D	9/20/2016
2	2B	12/7/2016
2	2A	3/1/2017
2	2G	6/13/2017
2	2F	6/21/2017
2	2E	9/1/2017
6	6A	12/20/2017
6	6B	12/20/2017
6	6C	1/9/2019

*CQA Certification date is the date NCDEQ approved the construction of each individual Subcell as ready for disposal

Public Staff
Garrett Exhibit 8

I/A Permit No.	Date	FID
1910-STRUC-2015	September 10th, 2019	1357866

RECEIVED
September 10th, 2019
Division of Waste Management
Solid Waste Section

September 5, 2019

Mr. Benjamin Jackson, Engineering Project Manager
Permitting Branch, Solid Waste Section
Division of Waste Management, NCDEQ
1646 Mail Service Center
Raleigh NC 27699

Re: Partial Closure Notification

Dear Mr. Jackson,

On behalf of Green Meadow, LLC and Charah, LLC. (Owner), HDR is providing the following partial closure notification for the Brickhaven No. 2 Mine Site Tract "A" Structural Fill (Permit No. 1910). It has been deemed by the Owner that areas will not receive additional coal combustion products, have reached or are below final structural grades, and are ready for closure.

Closure activities beginning in September, 2019 will include placement of the 40 mil LLDPE geomembrane, geocomposite, four feet of cover soil on the side slopes and a minimum of two feet of cover soil on the top deck meeting the approved specifications, and installation of the perimeter and cap drainage systems. The additional cap soils will be added at a later date in order to complete the closure.

The attached drawing identifies the areas previously capped and the areas to be capped under this notification.

When closure is complete HDR will compile a closure certification by a professional engineer stating closure occurred in accordance with the approved Closure/Post-Closure Plan for submittal to NCDEQ. Once closure of the entire structural fill is fully complete the Owner will record the structural fill with the Register of Deeds as required by NCGS 130A-309.219.

If you have any questions, comments, or require additional information, please contact me at 704.338.6843.

Sincerely,
HDR Engineering, Inc. of the Carolinas

Michael D. Plummer, PE
Project Manager

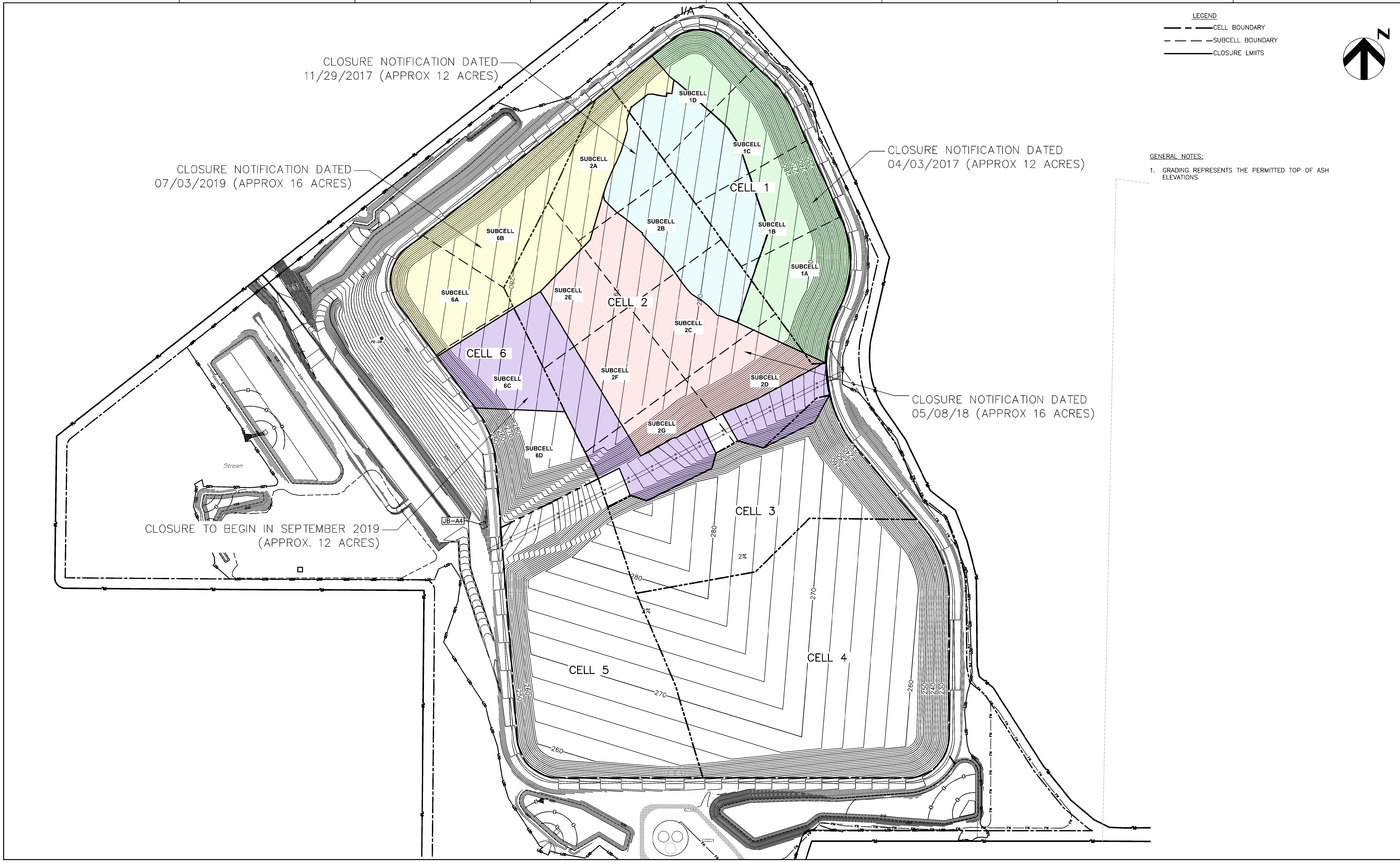
cc: Ed Mussler, NCDEQ (via electronic mail only)
Sherri Stanley, NCDEQ (via electronic mail only)
Tom Flannagan, Charah (via electronic mail only)
Norman Divers, Charah (via electronic mail only)
Greg Grambusch, Charah (via electronic mail only)

Attachments

– Brickhaven Mine – Closure Notification Drawing

hdrinc.com

440 S Church Street, Suite 1000, Charlotte, NC 28202-2075
704.338.6700



HDR

HDR Engineering Inc. of the Carolinas

440 S. Church St. Suite 1000
Charlotte, NC 28202-2075
704.338.6700
N.C.B.E.L.S. License Number F-0116

ISSUE	DATE	DESCRIPTION
1	9/19	APPROX CLOSURE LIMITS

PROJECT MANAGER	M.D. PLUMMER, P.E.
DESIGNED BY	
DRAWN BY	Z. PRIESTER
CHECKED BY	
PROJECT NUMBER	10021146

BRICKHAVEN No. 2 MINE TRACT "A" MINE
STRUCTURAL FILL
MONCURE, NC

CLOSURE AREA
CELL 6C, 2G SLOPE, AND
POWER LINE AREAS

0 1" 2"

FILENAME 00C-01.dwg

SCALE 1"=200'

SHEET 00C-01

Public Staff
Garrett Exhibit 9

Independent Development Cost Estimate for Brickhaven Stuctural Fill

Cost Category	Source for Basis Amount	Basis Amount	Adjusted Amount	Comments
Land Acquisition	Chatham County Tax Records	$ 11,873,700	$ 13,654,755	Add 15% for Acquisition Cost
Rail/Infrastructure	Original Amounts in Sutton & Riverbend Purchase Orders	$ 18,000,000	$ 27,000,000	Add 50% Contingency for Brickhaven Site
Mining Bond	Mine Permit	$ 500,000	$ 500,000	No Adjustment
Closure Cost	Financial Assurance Documents	$ 9,520,000	$ 9,520,000	Average $/acre cost in Closure Cost Estimate; 68 Acre area
Post Closure Cost	Financial Assurance Documents	$ 1,038,889	$ 1,038,889	68 acres/144 acres X $2,220,000 Post Closure Cost Amount
Cell Development	Estimate	$ 30,600,000	$ 30,600,000	$450,000/acre; 68 acre area
	Total	$ 71,532,589	$ 82,313,644	

Docket No. E-2, Sub 1219

Garrett Exhibit 10- all pages confidential

Docket No. E-2, Sub 1219

Garrett Exhibit 11- all pages confidential

Docket No. E-2, Sub 1219

Garrett Exhibit 12- all pages confidential

Public Staff
Garrett Exhibit 13

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 164

Docket No. E-2, Sub 1219

Date of Request:	**March 12, 2020**
Date of Response:	**March 20, 2020**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 164-2, was provided to me by the following individual(s): Trudy Morris, Project Manager II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Associate General Counsel
Duke Energy Progress

Request:

2. In the Sub 1142 rate case, DEP witness Kerin stated on page 14, lines 12-16 of his Rebuttal Testimony, "Potential siting and construction of a CCR landfill within portions of the Asheville 1982 basin and limited portions of the 1964 basin was evaluated as early as 2007 prior to the passage of CAMA. However, earthquake and seismic issues, and its physical proximity to the French Broad River prevented this option."
The Company's response to PS DR 124-2.f. in this docket states, "The Asheville CCR Landfill Solid Waste Permit (1119-INDUS) was issued on February 7, 2020. As part of the solid waste permit application, DEP received a Zoning Permit from Buncombe County for approval to construct and operate the CCR landfill."
a. Please provide a detailed narrative explanation and supporting documentation for why, as witness Kerin testified, the Company was prevented from pursuing siting and construction of a CCR landfill within portions of the 1982 and 1963 basins but has since succeeded in obtaining a permit to construct and operate a CCR landfill at the Asheville site. Please include any actions taken by the Company to address the specific impediments to the siting and construction of a landfill, including seismic issues, proximity to the French Broad River, and zoning, described by witness Kerin.
b. Please provide a detailed narrative and supporting documentation to explain why the Company is not pursuing a landfill at the Asheville site that is larger than the planned landfill.
c. Please provide all studies, reports, and analyses regarding alternative landfill options for the Asheville site evaluated by the Company.
d. Please provide a detailed narrative and supporting documentation to explain why the Company has not proposed to use areas within the 1964 basin at the Asheville site for landfill capacity.

Response:

a.The landfill which was conceptually sited over portions of the 1982 and 1964 basins was sized to provide 20 years of capacity and was significantly larger than the landfill currently being built on site (5.2 million tons of capacity vs 1.3 million tons). The site of the current landfill was evaluated and considered to be too small to meet the projected capacity needs in the 2007-2011 time period and was thus not further evaluated at that time.
Note that seismic issues were a significant factor in the design of a landfill sited over ash. Such a design required placement of stone columns and a stone mat to support the landfill during a design earthquake. Siting a landfill over natural soils, such as the landfill currently being built, does not face the same seismic risk and is stable under a design seismic event.
The proximity of the proposed over basin landfill and the current landfill both meet NC Solid Waste Management regulatory set backs, however the Buncombe County Zoning Board was concerned about the proposed landfill's proximity to the French Broad River given the seismic risk. Based on the board's concerns on this issue and others, and upon their recommendation, Progress Energy withdrew the Special Use Permit application for the over basin landfill and evaluated alternatives to constructing an onsite landfill including alternate on site locations, potential off site locations and redevelopment of the 1982

basin. These alternatives were evaluated by Golder Associates and their findings were documented in reports submitted to Progress Energy. DEP is currently trying to locate copies of these documents and will provide them as they are located.

b.Site constraints including wetlands, property buffers, and topography limit the footprint of any on site landfill and prevent it from having capacity beyond the designed 1.1 million yards of capacity. See the Onsite CCR Landfill Permit to Construct Application in the attached folder. Note that 2H:1V fill slopes and mechanically stabilized earthen (MSE) embankments with even steeper slopes were required to achieve the design capacity. The use of MSE walls at Asheville to support landfill development is the first time this technology has been used in the state of North Carolina to maximize landfill capacity.

c.Alternate landfill options were evaluated by Golder Associates and their findings were documented in multiple reports submitted to Progress Energy. DEP is currently trying to locate copies of these documents and will provide them as they are located.

d.The 1964 basin is not being used to site a landfill primarily because such use would require double handling of materials and temporary out of basin stockpiling of materials. NC Dam Safety regulations require that a CCR basin be able to provide capacity for two Probable Maximum Precipitation storm events if the spillway structure has been removed as has been done at the Asheville Station. Excavation of ash from the basin and decommissioning of the dam which has significant ash within its structure has to be completed in stages to meet this requirement (see Asheville Steam Electric Generating Plant Dam Decommissioning Request (ASH-151), in the attached folder). In order to build and operate a landfill in the basin, ash would have to be stored outside the 1964 basin in a lined facility, the in-basin landfill built, stormwater control features built, and the dam partially decommissioned before a landfill could be operated within the basin. Since the landfill currently being built can hold the estimated ash remaining at the site, there was no need to plan for additional capacity, and the possibility of building a landfill within the 1964 basin and its associated expenses was not further evaluated.
Note that the presence of springs and issues associated with surface water flows through the decommissioned basin would limit the capacity of any landfill sited within the 1964 basin. Although these issues have not been extensively evaluated, they would likely limit the size of any landfill developed in the 1964 basin to a similar size to the landfill currently being constructed.

Public Staff
Hinton Exhibit 4

Duke Energy Progress, LLC
First Mortgage Bonds
Moody's Historical Ratings

Date	Rating	Rating Action
01 Aug 2018	Aa3	RATING AFFIRMATION
12 May 2017	Aa3	RATING AFFIRMATION
13 Jan 2016	Aa3	Downgrade
27 Oct 2015	Aa2	ON WATCH for Possible Downgrade
05 Jun 2015	Aa2	RATING AFFIRMATION
31 Jan 2014	Aa2	Upgrade
08 Nov 2013	Aa3	ON WATCH for Possible Upgrade
25 Sep 2013	Aa3	Upgrade
09 Jul 2013	A1	ON WATCH for Possible Upgrade
03 Aug 2009	A1	Upgrade
15 Jun 2007	A2	Upgrade
14 May 2007	A3	ON WATCH for Possible Upgrade
18 Oct 2002	A3	Confirmed
22 Nov 2000	A3	Downgrade
23 Aug 1999	A2	Confirmed
11 Nov 1998	A2	Confirmed
26 Apr 1982	A2	Modified Rating Notation
23 Sep 1977	A	Upgrade
28 Feb 1975	Baa	Downgrade

Public Staff
Hinton Exhibit 5

DEP's Qualified Decommissioning Trust Fund

Unit	Qualified After-Tax Rate of Return	De-Risked Qualified After Tax Rate of Return	Escalation Rate
Robinson Unit 2	4.50%	1.84%	2.73%
Brunswick Unit 1	4.49%	1.84%	2.82%
Brunswick Unit 2	4.57%	1.84%	2.80%
Shearon Harris	4.68%	1.84%	2.61%
Average	4.56%	1.84%	2.74%

Souce: Docket No. E-2, Sub 1142, Doss Exhibit 2.

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Public Staff Data Request No. 121
Distribution Vegetation Management
Response to Question #1

Question #1

Please provide an update to PSDR 7-5 to also include calendar year 2019 through year-end.

Dist Veg Mgmt Response

Programs	2014			
DEP Distribution Veg Mgmt	Budget	Actual	Variance	Variance Explanation
Reactive	$ 5,060,000	$ 3,138,116	-38%	Reduction in Contract Forester workforce associated with customer ticket planning and execution.
Maintenance/Trimming	$ 36,482,397	$ 40,778,250	12%	Technical specification changes were implemented.
Herbicide	$ 1,540,545	$ 1,399,919	-9%	Program cost less than original forecast.
Contract Inspectors	$ -	$ 186,952	-	Added Contract Inspectors.
Hazard Tree	$ 6,024,596	$ 3,008,430	-50%	Less hazard trees identified than original forecast.

Workplan Summary	2014			
DEP Distribution Veg Mgmt	Annual Plan (Miles)	Actual Completed (Miles)	Variance	Variance Explanation
Total Annual Maintenance Trim Miles	6,278	6,259	0%	
Total Herbicide/Sprayed Miles	6,829	6,785	-1%	

Programs	2015			
DEP Distribution Veg Mgmt	Budget	Actual	Variance	Variance Explanation
Reactive	$ 2,996,200	$ 2,891,070	-4%	
Maintenance/Trimming	$ 39,144,068	$ 36,177,141	-8%	Cost per mile less than forecast due to less complex miles in the work plan
Herbicide	$ 1,359,400	$ 1,351,768	-1%	
Contract Inspectors	$ 288,000	$ 311,138	8%	Added additional Contract Foresters with focus on contractor safety
Hazard Tree	$ 8,708,207	$ 4,924,521	-43%	Less hazard trees identified than original forecast.

Workplan Summary	2015			
DEP Distribution Veg Mgmt	Annual Plan (Miles)	Actual Completed (Miles)	Variance	Variance Explanation
Total Annual Maintenance Trim Miles	5,972	5,867	-2%	
Total Herbicide/Sprayed Miles	6,314	6,314	0%	

Programs	2016			
DEP Distribution Veg Mgmt	Budget	Actual	Variance	Variance Explanation
Reactive	$ 2,714,124	$ 1,842,060	-32%	Costs associated with resolving customer issues less than forecast
Maintenance/Trimming	$ 37,074,117	$ 34,694,781	-6%	Cost per mile less than forecast due to less complex miles in the work plan
Herbicide	$ 1,998,588	$ 2,003,992	0%	
Contract Inspectors	$ 293,760	$ 451,500	54%	Added additional Contract Foresters with focus on contractor safety
Hazard Tree	$ 6,772,475	$ 3,439,326	-49%	Less hazard trees identified than original forecast.

Workplan Summary	2016			
DEP Distribution Veg Mgmt	Annual Plan (Miles)	Actual Completed (Miles)	Variance	Variance Explanation
Total Annual Maintenance Trim Miles	5,620	5,759	2%	
Total Herbicide/Sprayed Miles	9,762	9,762	0%	

Programs	2017			
DEP Distribution Veg Mgmt	Budget	Actual	Variance	Variance Explanation
Reactive	$ 2,714,124	$ 2,314,017	-15%	Costs associated with resolving customer issues less than forecast
Maintenance/Trimming	$ 38,126,849	$ 35,568,144	-7%	Cost per mile less than forecast due to less complex miles in the work plan
Herbicide	$ 2,733,122	$ 2,277,329	-17%	Herbicide plan costs less than projected due to less stem density resulting in use of less herbicide
Contract Inspectors	$ 572,635	$ 622,328	9%	Added additional Contract Foresters with focus on contractor safety
Hazard Tree	$ 6,820,802	$ 7,526,542	10%	Additional hazard trees were identified and removed.

Workplan Summary	2017			
DEP Distribution Veg Mgmt	Annual Plan (Miles)	Actual Completed (Miles)	Variance	Variance Explanation
Total Annual Maintenance Trim Miles	5,914	5,933	0%	
Total Herbicide/Sprayed Miles	11,439	11,439	0%	

Programs	2018			
DEP Distribution Veg Mgmt	Budget	Actual	Variance	Variance Explanation
Reactive	$ 2,760,536	$ 2,382,338	-14%	Costs associated with resolving customer issues less than forecast
Maintenance/Trimming	$ 32,871,357	$ 31,730,273	-3%	
Herbicide	$ 2,172,876	$ 1,963,007	-10%	Herbicide plan costs less than projected due to less stem density resulting in use of less herbicide
Contract Inspectors	$ 550,000	$ 439,685	-20%	Reduction in Contract Forester positions to match workload and safey oversight accountabilities
Hazard Tree	$ 8,531,860	$ 4,992,103	-41%	Deferred some removals to 2019 due to storms.

Workplan Summary	2018			
DEP Distribution Veg Mgmt	Annual Plan (Miles)	Actual Completed (Miles)	Variance	Variance Explanation
Total Annual Maintenance Trim Miles	4,551	4,458	-2%	
Total Herbicide/Sprayed Miles	10,573	10,573	0%	

Programs	2019			
DEP Distribution Veg Mgmt	Budget	Actual	Variance	Variance Explanation
Reactive	$ 2,898,560	$ 2,617,666	-10%	Costs associated with resolving customer issues less than forecast
Maintenance/Trimming	$ 30,661,734	$ 34,306,936	12%	Cost per mile less than forecast due to less complex miles in the work plan
Herbicide	$ 2,694,332	$ 1,905,241	-29%	Less miles due for treatment than originally projected and less stem density resulted in use of less herbicide.
Contract Inspectors	$ 636,000	$ 506,900	-20%	Assigned Contract Foresters to audit Hazard Trees
Hazard Tree	$ 7,441,755	$ 12,223,460	64%	Removed trees identifed in 2018 as well as trees identified 2019.

Workplan Summary	2019			
DEP Distribution Veg Mgmt	Annual Plan (Miles)	Actual Completed (Miles)	Variance	Variance Explanation
Total Annual Maintenance Trim Miles	4,800	4,803	0%	
Total Herbicide/Sprayed Miles	10,328	10,328	0%	

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Public Staff Data Request No. 79.4 and 79.5

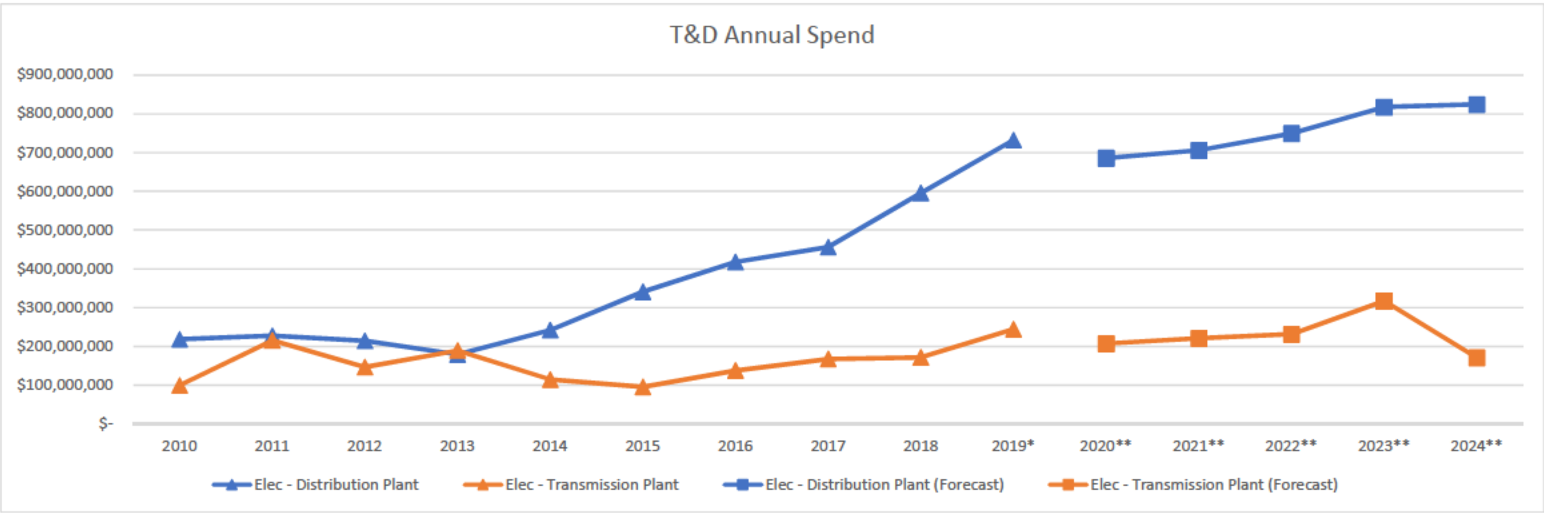
Public Staff
T&D Williamson Exhibit 2

	2010	2011	2012	2013	2014	2015	2016	2017	2018
	FERC Form 1	FERC Form 1	FERC Form 1	FERC Form 1	FERC Form 1	FERC Form 1	FERC Form 1	FERC Form 1	FERC Form 1
Elec - Distribution Plant	218,830,720	227,255,853	214,549,404	179,179,698	242,406,139	341,229,561	417,747,108	456,461,861	596,145,535
Elec - Transmission Plant	99,573,476	215,868,225	146,756,771	189,440,272	114,662,543	95,586,934	137,888,317	167,725,489	171,758,268
Elec - Distribution Plant (Forecast)									
Elec - Transmission Plant (Forecast)									

	2019*	2020**	2021**	2022**	2023**	2024**
	Internal Reporting	forecast	forecast	forecast	forecast	forecast
Elec - Distribution Plant	732,442,649					
Elec - Transmission Plant	244,880,986					
Elec - Distribution Plant (Forecast)		685,634,233	705,765,721	749,602,910	817,845,238	824,361,414
Elec - Transmission Plant (Forecast)		207,181,065	220,688,000	231,455,044	317,285,792	170,958,004

* 2019 based on internal reporting until FERC Form 1 is filed

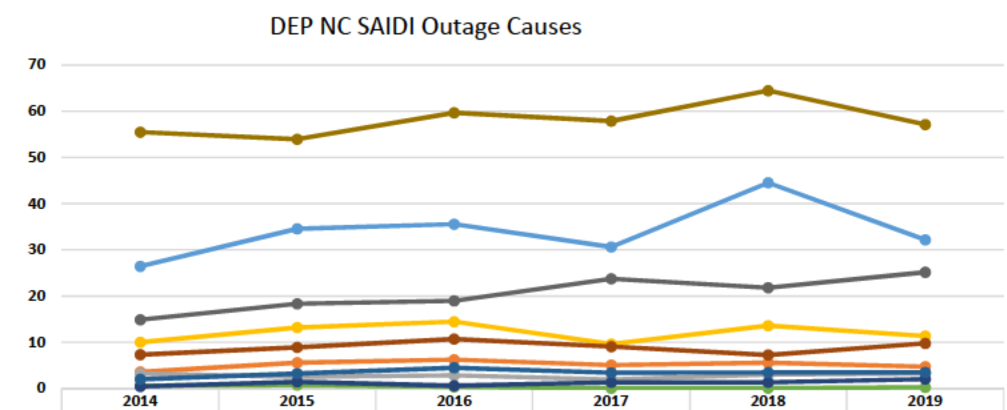
** **Projected forecasts that are subject to change.**



Row Labels	Reliability SAIDI 2014	2015	2016	2017	2018	2019
DEP NC	**123.88**	**142.13**	**153.67**	**142.59**	**164.92**	**149.13**
Design Issue	3.56	5.54	6.22	5.05	5.54	4.72
Duke Error	3.22	2.46	2.83	1.91	3.01	3.24
Environment	9.99	13.18	14.43	9.60	13.55	11.34
Equipment Failure	26.44	34.54	35.57	30.64	44.51	32.16
Other	0.64	0.71	0.30	0.03	0.05	0.21
Other Human Events	0.41	1.40	0.58	1.33	1.30	2.01
Planned Work	7.32	8.87	10.68	9.05	7.24	9.74
Public Accident	14.86	18.29	18.98	23.73	21.79	25.13
Vegetation	55.48	53.94	59.64	57.89	64.47	57.12
Wildlife	1.95	3.20	4.45	3.36	3.46	3.47

Source:
Docket No. E-7, SUB 1214
Public Staff DR 166

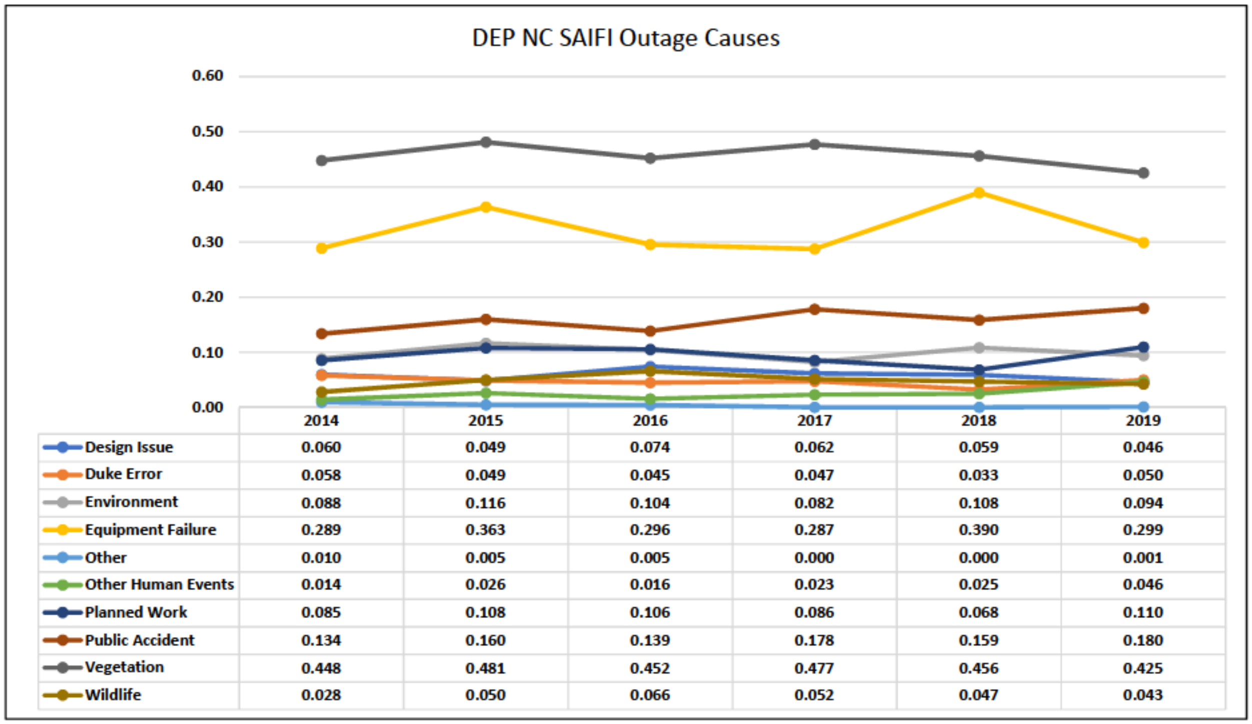
Public Staff
T&D Williamson Exhibit 3
Page 1 of 5



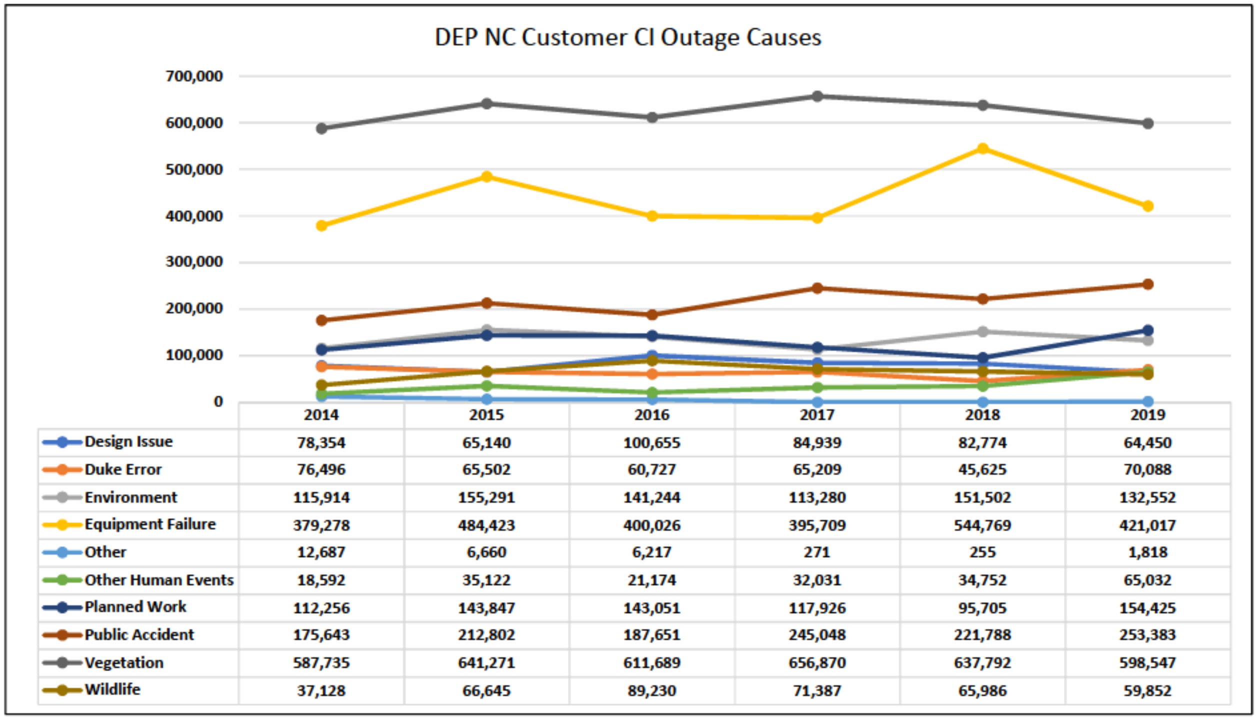
	2014	2015	2016	2017	2018	2019
Design Issue	3.56	5.54	6.22	5.05	5.54	4.72
Duke Error	3.22	2.46	2.83	1.91	3.01	3.24
Environment	9.99	13.18	14.43	9.60	13.55	11.34
Equipment Failure	26.44	34.54	35.57	30.64	44.51	32.16
Other	0.64	0.71	0.30	0.03	0.05	0.21
Other Human Events	0.41	1.40	0.58	1.33	1.30	2.01
Planned Work	7.32	8.87	10.68	9.05	7.24	9.74
Public Accident	14.86	18.29	18.98	23.73	21.79	25.13
Vegetation	55.48	53.94	59.64	57.89	64.47	57.12
Wildlife	1.95	3.20	4.45	3.36	3.46	3.47

I/A

Row Labels	Reliability SAIFI					
	2014	2015	2016	2017	2018	2019
DEP NC	**1.214**	**1.408**	**1.302**	**1.295**	**1.345**	**1.294**
Design Issue	0.060	0.049	0.074	0.062	0.059	0.046
Duke Error	0.058	0.049	0.045	0.047	0.033	0.050
Environment	0.088	0.116	0.104	0.082	0.108	0.094
Equipment Failure	0.289	0.363	0.296	0.287	0.390	0.299
Other	0.010	0.005	0.005	0.000	0.000	0.001
Other Human Events	0.014	0.026	0.016	0.023	0.025	0.046
Planned Work	0.085	0.108	0.106	0.086	0.068	0.110
Public Accident	0.134	0.160	0.139	0.178	0.159	0.180
Vegetation	0.448	0.481	0.452	0.477	0.456	0.425
Wildlife	0.028	0.050	0.066	0.052	0.047	0.043



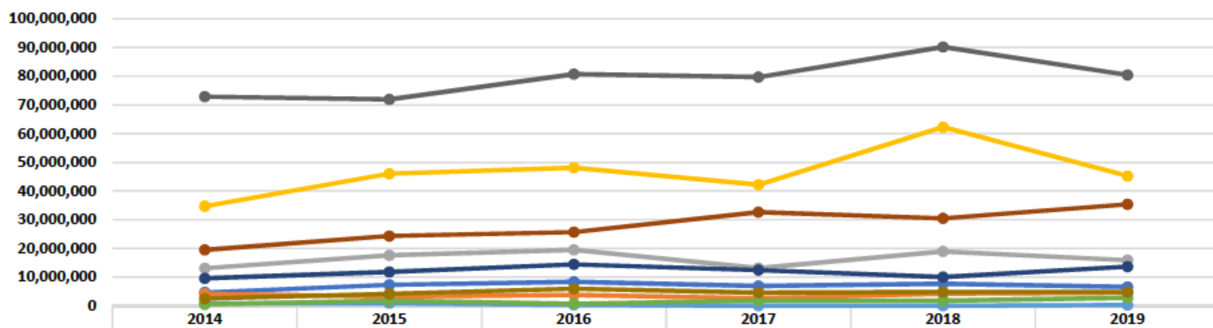
Row Labels	Customer CI 2014	2015	2016	2017	2018	2019
DEP NC	**1,594,083**	**1,876,703**	**1,761,664**	**1,782,670**	**1,880,948**	**1,821,164**
Design Issue	78,354	65,140	100,655	84,939	82,774	64,450
Duke Error	76,496	65,502	60,727	65,209	45,625	70,088
Environment	115,914	155,291	141,244	113,280	151,502	132,552
Equipment Failure	379,278	484,423	400,026	395,709	544,769	421,017
Other	12,687	6,660	6,217	271	255	1,818
Other Human Events	18,592	35,122	21,174	32,031	34,752	65,032
Planned Work	112,256	143,847	143,051	117,926	95,705	154,425
Public Accident	175,643	212,802	187,651	245,048	221,788	253,383
Vegetation	587,735	641,271	611,689	656,870	637,792	598,547
Wildlife	37,128	66,645	89,230	71,387	65,986	59,852



Public Staff
T&D Williamson Exhibit 3
Page 4 of 5

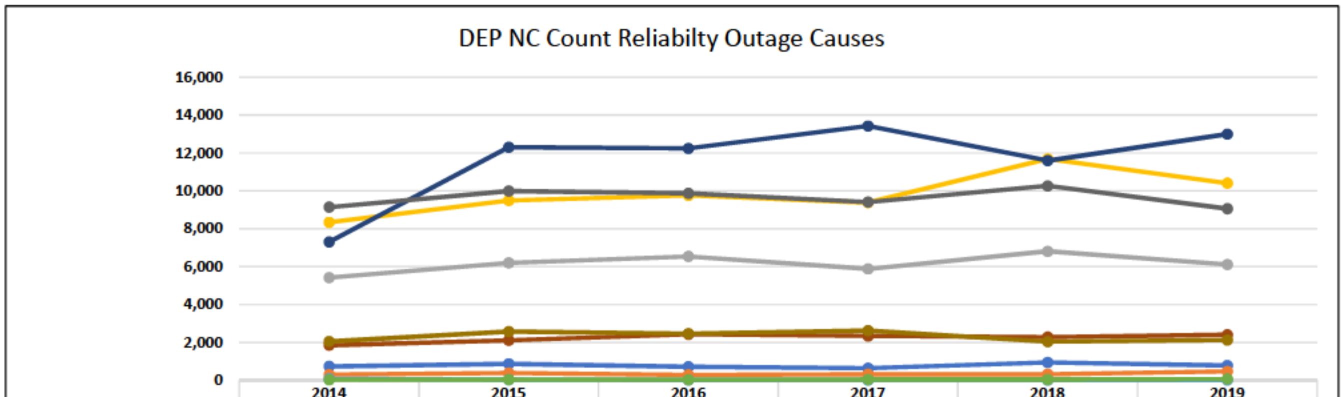
Row Labels	Customer CMI 2014	2015	2016	2017	2018	2019
DEP NC	**162,649,372**	**189,463,126**	**207,965,303**	**196,341,340**	**230,637,594**	**209,932,515**
Design Issue	4,680,237	7,386,317	8,415,419	6,947,439	7,743,829	6,649,982
Duke Error	4,227,766	3,275,832	3,831,873	2,628,896	4,212,124	4,553,878
Environment	13,120,959	17,572,492	19,533,039	13,225,179	18,952,364	15,964,575
Equipment Failure	34,710,762	46,043,780	48,137,714	42,184,748	62,249,645	45,271,637
Other	842,723	952,551	404,558	39,970	70,967	290,764
Other Human Events	537,234	1,861,602	788,943	1,832,150	1,822,758	2,823,479
Planned Work	9,605,100	11,829,273	14,447,329	12,465,180	10,118,328	13,710,972
Public Accident	19,514,971	24,375,219	25,682,263	32,672,734	30,468,703	35,374,638
Vegetation	72,848,341	71,905,859	80,708,485	79,713,827	90,154,468	80,406,662
Wildlife	2,561,278	4,260,202	6,015,681	4,631,216	4,844,409	4,885,928

DEP NC Customer CMI Outage Causes



	2014	2015	2016	2017	2018	2019
Design Issue	4,680,237	7,386,317	8,415,419	6,947,439	7,743,829	6,649,982
Duke Error	4,227,766	3,275,832	3,831,873	2,628,896	4,212,124	4,553,878
Environment	13,120,959	17,572,492	19,533,039	13,225,179	18,952,364	15,964,575
Equipment Failure	34,710,762	46,043,780	48,137,714	42,184,748	62,249,645	45,271,637
Other	842,723	952,551	404,558	39,970	70,967	290,764
Other Human Events	537,234	1,861,602	788,943	1,832,150	1,822,758	2,823,479
Planned Work	9,605,100	11,829,273	14,447,329	12,465,180	10,118,328	13,710,972
Public Accident	19,514,971	24,375,219	25,682,263	32,672,734	30,468,703	35,374,638
Vegetation	72,848,341	71,905,859	80,708,485	79,713,827	90,154,468	80,406,662
Wildlife	2,561,278	4,260,202	6,015,681	4,631,216	4,844,409	4,885,928

Row Labels	Counts Reliability Outages					
	2014	**2015**	**2016**	**2017**	**2018**	**2019**
DEP NC	**35,243**	**44,001**	**44,333**	**44,071**	**46,008**	**44,417**
Design Issue	739	873	708	642	940	788
Duke Error	303	381	284	327	325	471
Environment	5,417	6,201	6,532	5,881	6,810	6,111
Equipment Failure	8,339	9,496	9,756	9,384	11,685	10,404
Other	82	34	12	9	7	4
Other Human Events	27	38	34	42	48	61
Planned Work	7,304	12,309	12,239	13,425	11,602	13,000
Public Accident	1,851	2,108	2,429	2,336	2,284	2,402
Vegetation	9,137	9,988	9,871	9,403	10,264	9,059
Wildlife	2,044	2,573	2,468	2,622	2,043	2,117



	2014	2015	2016	2017	2018	2019
Design Issue	739	873	708	642	940	788
Duke Error	303	381	284	327	325	471
Environment	5,417	6,201	6,532	5,881	6,810	6,111
Equipment Failure	8,339	9,496	9,756	9,384	11,685	10,404
Other	82	34	12	9	7	4
Other Human Events	27	38	34	42	48	61
Planned Work	7,304	12,309	12,239	13,425	11,602	13,000
Public Accident	1,851	2,108	2,429	2,336	2,284	2,402
Vegetation	9,137	9,988	9,871	9,403	10,264	9,059
Wildlife	2,044	2,573	2,468	2,622	2,043	2,117

I/A

Grid Transformation Matrix
Driving Question: What is "grid transformation", and how do we determine whether each program fits that designation?

		Focus	Optimize	Optimize	Optimize	Optimize
		Program Number (Oliver Exhibit 10)	1	1	1	1
		Component Number	1	2	3	4
		Reference	**1.1**	**1.2**	**1.3**	**1.4**
		Program	**Self Optimizing Grid**			
Weight	**Metric**	**Component** **Metric Rankings**	**Capacity Projects**	**Connectivity Projects**	**Automation Projects**	**Advanced Distribution Management System (ADMS)**
2	**TRANSFORMATIVE:** Does the program allow the utility to do something **on the grid** that it could not do before?	1 = No new capabilities; current procedures provide similar capabilities 2 = Adds some limited new capabilities 3 = Adds significant new capabilities	1.0	1.0	3.0	3.0
1	**TIMING:** What is the level of urgency to complete this program?	1 = Ongoing work; continue normal pace 2 = New work; 3-year timeline is not critical to grid op 3 = Urgent; 3-year timeline is critical to grid op	1.0	1.0	2.0	2.0
1	**GRID ARCHITECTURE:** How does this program fit into the broader grid modernization architecture?	1 = This program is standalone and operates outside grid modernization architecture. 2 = This program is an application dependent upon core components. 3 = This program is a core component of grid mod (foundational).	3.0	3.0	3.0	3.0
	Weighted Grid Transformation Score (min=4; max=12)		**6**	**6**	**11**	**11**

Grid Transformation Matrix
Driving Question: What is "grid transformation", and how do we determine whether each program fits that designation?

Weight	Metric	Metric Rankings					
		Focus	Optimize	Optimize	Optimize	Optimize	Optimize
		Program Number (Oliver Exhibit 10)	2	3	4	5	5
		Component Number				1	2
		Reference	**2.**	**3.**	**4.**	**5.1**	**5.2**
		Program	**Distribution Hardening and Resiliency - Flood Hardening**	**Distribution Transformer Retrofit**	**DSDR additon to enable CVR**	**Transmission Hard Resiliency**	
		Component				**Line H&R**	**Substation Flooding H&R**
2	**TRANSFORMATIVE:** Does the program allow the utility to do something **on the grid** that it could not do before?	1 = No new capabilities; current procedures provide similar capabilities 2 = Adds some limited new capabilities 3 = Adds significant new capabilities	1.0	1.0	2.0	1.0	1.0
1	**TIMING:** What is the level of urgency to complete this program?	1 = Ongoing work; continue normal pace 2 = New work; 3-year timeline is not critical to grid op 3 = Urgent; 3-year timeline is critical to grid op	1.0	1.0	1.0	1.0	1.0
1	**GRID ARCHITECTURE:** How does this program fit into the broader grid modernization architecture?	1 = This program is standalone and operates outside grid modernization architecture. 2 = This program is an application dependent upon core components. 3 = This program is a core component of grid mod (foundational).	1.0	3.0	2.0	1.0	1.0
	Weighted Grid Transformation Score (min=4; max=12)		**4**	**6**	**7**	**4**	**4**

Grid Transformation Matrix
Driving Question: What is "grid transformation", and how do we determine whether each program fits that designation?

		Focus	Optimize	Optimize	Modernize	Optimize
		Program Number (Oliver Exhibit 10)	5	6	7	8
		Component Number	3			1
		Reference	5.3	6.	7.	8.1
		Program	ening &	Transformer Bank Replacements	Transmission System Intelligence	Oil Breaker Re
Weight	**Metric**	**Component** / **Metric Rankings**	**Substation Animal Mitigation**			**Transmission Class (SF6)**
2	**TRANSFORMATIVE:** Does the program allow the utility to do something **on the grid** that it could not do before?	1 = No new capabilities; current procedures provide similar capabilities 2 = Adds some limited new capabilities 3 = Adds significant new capabilities	1.0	1.0	3.0	1.0
1	**TIMING:** What is the level of urgency to complete this program?	1 = Ongoing work; continue normal pace 2 = New work; 3-year timeline is not critical to grid op 3 = Urgent; 3-year timeline is critical to grid op	1.0	1.0	2.0	1.0
1	**GRID ARCHITECTURE:** How does this program fit into the broader grid modernization architecture?	1 = This program is standalone and operates outside grid modernization architecture. 2 = This program is an application dependent upon core components. 3 = This program is a core component of grid mod (foundational).	1.0	3.0	3.0	3.0
	Weighted Grid Transformation Score (min=4; max=12)		**4**	**6**	**11**	**6**

Grid Transformation Matrix
Driving Question: What is "grid transformation", and how do we determine whether each program fits that designation?

Weight	Metric					
		Focus	Optimize	Optimize	Optimize	Modernize
		Program Number (Oliver Exhibit 10)	8	9	11	12
		Component Number	2			1
		Reference	**8.2**	**9.**	**11.**	**12.1**
		Program	**placements**	**Targeted Underground (TUG)**	**Long Duration Int/High Impact Sites**	
Weight	**Metric**	**Component** / **Metric Rankings**	**Distribution Class (Vacuum)**			**Next Generation Cellular**
2	**TRANSFORMATIVE:** Does the program allow the utility to do something **on the grid** that it could not do before?	1 = No new capabilities; current procedures provide similar capabilities 2 = Adds some limited new capabilities 3 = Adds significant new capabilities	1.0	1.0	1.0	1.0
1	**TIMING:** What is the level of urgency to complete this program?	1 = Ongoing work; continue normal pace 2 = New work; 3-year timeline is not critical to grid op 3 = Urgent; 3-year timeline is critical to grid op	1.0	1.0	1.0	3.0
1	**GRID ARCHITECTURE:** How does this program fit into the broader grid modernization architecture?	1 = This program is standalone and operates outside grid modernization architecture. 2 = This program is an application dependent upon core components. 3 = This program is a core component of grid mod (foundational).	3.0	1.0	1.0	3.0
	Weighted Grid Transformation Score (min=4; max=12)		**6**	**4**	**4**	**8**

Grid Transformation Matrix
Driving Question: What is "grid transformation", and how do we determine whether each program fits that designation?

		Focus	Modernize	Modernize	Modernize	Modernize
		Program Number (Oliver Exhibit 10)	12	12	12	12
		Component Number	2	3	4	5
		Reference	12.2	12.3	12.4	12.5
		Program	Enterprise Communi			
Weight	**Metric**	**Component** **Metric Rankings**	**Mission Critical Voice**	**POC**	**BizWAN**	**GridWAN**
2	**TRANSFORMATIVE:** Does the program allow the utility to do something **on the grid** that it could not do before?	1 = No new capabilities; current procedures provide similar capabilities 2 = Adds some limited new capabilities 3 = Adds significant new capabilities	1.0	1.0	1.0	1.0
1	**TIMING:** What is the level of urgency to complete this program?	1 = Ongoing work; continue normal pace 2 = New work; 3-year timeline is not critical to grid op 3 = Urgent; 3-year timeline is critical to grid op	1.0	1.0	1.0	1.0
1	**GRID ARCHITECTURE:** How does this program fit into the broader grid modernization architecture?	1 = This program is standalone and operates outside grid modernization architecture. 2 = This program is an application dependent upon core components. 3 = This program is a core component of grid mod (foundational).	3.0	1.0	3.0	3.0
	Weighted Grid Transformation Score (min=4; max=12)		6	4	6	6

Grid Transformation Matrix
Driving Question: What is "grid transformation", and how do we determine whether each program fits that designation?

		Focus	Modernize	Modernize	Modernize	Modernize
		Program Number (Oliver Exhibit 10)	12	12	12	12
		Component Number	6	7	8	9
		Reference	12.6	12.7	12.8	12.9
		Program	cations			
Weight	Metric	Component Metric Rankings	Mission Critical Transport	Tower, shelters, and Power Supplies	Network Asset Systems	Vehicle Area Network
2	**TRANSFORMATIVE:** Does the program allow the utility to do something **on the grid** that it could not do before?	1 = No new capabilities; current procedures provide similar capabilities 2 = Adds some limited new capabilities 3 = Adds significant new capabilities	1.0	1.0	1.0	1.0
1	**TIMING:** What is the level of urgency to complete this program?	1 = Ongoing work; continue normal pace 2 = New work; 3-year timeline is not critical to grid op 3 = Urgent; 3-year timeline is critical to grid op	1.0	1.0	2.0	2.0
1	**GRID ARCHITECTURE:** How does this program fit into the broader grid modernization architecture?	1 = This program is standalone and operates outside grid modernization architecture. 2 = This program is an application dependent upon core components. 3 = This program is a core component of grid mod (foundational).	3.0	3.0	2.0	2.0
	Weighted Grid Transformation Score (min=4; max=12)		**6**	**6**	**6**	**6**

Grid Transformation Matrix
Driving Question: What is "grid transformation", and how do we determine whether each program fits that designation?

Weight	Metric	Metric Rankings				
		Focus	Modernize	Modernize	Modernize	Modernize
		Program Number (Oliver Exhibit 10)	13	13	13	13
		Component Number	1	2	3	4
		Reference	**13.1**	**13.2**	**13.3**	**13.4**
		Program	**Distribution Automation**			
		Component	**Hydraulic to Electronic Recloser**	**System Intelligence and Monitoring**	**Fuse Replacement**	**UG System Automation**
2	**TRANSFORMATIVE:** Does the program allow the utility to do something **on the grid** that it could not do before?	1 = No new capabilities; current procedures provide similar capabilities 2 = Adds some limited new capabilities 3 = Adds significant new capabilities	2.0	2.0	2.0	3.0
1	**TIMING:** What is the level of urgency to complete this program?	1 = Ongoing work; continue normal pace 2 = New work; 3-year timeline is not critical to grid op 3 = Urgent; 3-year timeline is critical to grid op	1.0	1.0	1.0	2.0
1	**GRID ARCHITECTURE:** How does this program fit into the broader grid modernization architecture?	1 = This program is standalone and operates outside grid modernization architecture. 2 = This program is an application dependent upon core components. 3 = This program is a core component of grid mod (foundational).	3.0	3.0	3.0	3.0
	Weighted Grid Transformation Score (min=4; max=12)		**8**	**8**	**8**	**11**

Grid Transformation Matrix
Driving Question: What is "grid transformation", and how do we determine whether each program fits that designation?

		Focus	Modernize	Modernize	Modernize	Modernize
		Program Number (Oliver Exhibit 10)	14	15	16	18
		Component Number				
		Reference	**14.**	**15.**	**16.**	**18.**
Weight	**Metric**	**Program** / **Component** / **Metric Rankings**	**Enterprise Applications**	**ISOP**	**DER Dispatch Tool**	**Power Electronics for Volt/VAR Control**
2	**TRANSFORMATIVE:** Does the program allow the utility to do something **on the grid** that it could not do before?	1 = No new capabilities; current procedures provide similar capabilities 2 = Adds some limited new capabilities 3 = Adds significant new capabilities	2.0	3.0	2.0	2.0
1	**TIMING:** What is the level of urgency to complete this program?	1 = Ongoing work; continue normal pace 2 = New work; 3-year timeline is not critical to grid op 3 = Urgent; 3-year timeline is critical to grid op	1.0	3.0	1.0	2.0
1	**GRID ARCHITECTURE:** How does this program fit into the broader grid modernization architecture?	1 = This program is standalone and operates outside grid modernization architecture. 2 = This program is an application dependent upon core components. 3 = This program is a core component of grid mod (foundational).	2.0	3.0	2.0	3.0
	Weighted Grid Transformation Score (min=4; max=12)		**7**	**12**	**7**	**9**

Grid Transformation Matrix
Driving Question: What is "grid transformation", and how do we determine whether each program fits that designation?

		Focus	Protect	Protect	Protect	Protect	Protect
		Program Number (Oliver Exhibit 10)	19	19	19	19	19
		Component Number	1	2	3	4	5
		Reference	19.1	19.2	19.3	19.4	19.5
		Program	Physical and Cyber Security				
Weight	**Metric**	**Component** **Metric Rankings**	**Substation Physical security**	**Windows Based unit change outs**	**Device entry alert system**	**Secure Access Device Management**	**Line Device Protection**
2	**TRANSFORMATIVE:** Does the program allow the utility to do something **on the grid** that it could not do before?	1 = No new capabilities; current procedures provide similar capabilities 2 = Adds some limited new capabilities 3 = Adds significant new capabilities	1.0	1.0	2.0	2.0	2.0
1	**TIMING:** What is the level of urgency to complete this program?	1 = Ongoing work; continue normal pace 2 = New work; 3-year timeline is not critical to grid op 3 = Urgent; 3-year timeline is critical to grid op	1.0	1.0	1.0	1.0	1.0
1	**GRID ARCHITECTURE:** How does this program fit into the broader grid modernization architecture?	1 = This program is standalone and operates outside grid modernization architecture. 2 = This program is an application dependent upon core components. 3 = This program is a core component of grid mod (foundational).	1.0	1.0	3.0	2.0	3.0
	Weighted Grid Transformation Score (min=4; max=12)		4	4	8	7	8

I/A

Public Staff
T&D Williamson Exhibit 5

Summary	DEP20	DEP21	DEP22	DEP Total
Total Grid Improvement Plan (NC only)	$236	$356	$469	**$1060.3**
Total Requested Deferral	$228	$331	$429	**$987.8**
Electric 'Extraordinary TYPE'	$53	$66	$68	**$186.1**

All dollars in millions; reflects capital budget allocated to North Carolina

Description	Forward to Acounting as Extraordinary TYPE	Requested Deferral	DEP 2020	DEP 2021	DEP 2022	DEP Total
SOG Automation + Control	YES	Yes	$36.1	$44.4	$49.1	**$129.6**
Transmission System Intelligence	YES	Yes	$6.8	$11.3	$5.6	**$23.7**
SOG ADMS	YES	Yes	$6.0	$5.7	$7.4	**$19.1**
UG System automation	YES	Yes	$1.8	$4.3	$5.1	**$11.2**
ISOP	YES	Yes	$1.8	$0.2	$0.4	**$2.5**
DSDR to CVR (IVVC)	No	Yes	-	$5.0	$5.0	**$10.0**
SOG Capacity & Connectivity	No	Yes	$19.4	$36.0	$98.2	**$153.6**
Trans CB Replace - SF6	No	Yes	$9.5	$7.9	$25.1	**$42.5**
Trans Line H&R	No	Yes	$0.6	$8.7	$10.8	**$20.1**
Mission Critical Transport	No	Yes	$13.3	$11.4	$18.1	**$42.8**
Fuse Replacement	No	Yes	$5.0	$23.8	$22.0	**$50.8**
TUG	No	Yes	$8.6	$19.5	$26.6	**$54.7**
Storage	No	No	$8.1	$24.1	$40.3	**$72.5**
Subst physical security	No	Yes	$7.7	$20.2	$28.4	**$56.3**
Hydraulic recloser replace	No	Yes	$9.0	$4.0	$0.9	**$13.9**
TX Bank Replacements	No	Yes	$25.0	$38.5	$19.2	**$82.8**
Enterprise applicaions	No	Yes	$1.4	$3.2	$6.2	**$10.8**
Towers, shelters	No	Yes	$3.5	$2.3	$2.1	**$7.9**
Dist CB Replace - Vacuum	No	Yes	$10.1	$12.1	$19.9	**$42.1**
Long Duration outage	No	Yes	$6.9	$5.0	$3.9	**$15.8**
Mission Critical Voice	No	Yes	$0.1	$12.9	$29.1	**$42.2**
Dist Tx Retrofit	No	Yes	$30.1	$42.1	$37.6	**$109.7**
GridWAN	No	Yes	$5.2	$2.6	$0.1	**$7.9**
Next Gen Cellular	No	Yes	$2.6	$2.6	$0.3	**$5.5**
Dist System intell/monitor	No	Yes	$0.6	$0.7	$1.7	**$3.0**
DER Dispatch	No	Yes	$1.1	$1.3	$0.5	**$2.9**
Secure Access Device Mgmt.	No	Yes	$1.1	$1.0	$0.7	**$2.7**
Line Device Protection	No	Yes	$4.1	$2.3	$1.9	**$8.3**
Trans Animal mitigation	No	Yes	-	$0.0	$0.4	**$0.4**
Device Entry Alert System	No	Yes	$0.8	$0.5	-	**$1.2**
Network Asset Systems	No	Yes	$0.2	$0.3	$0.2	**$0.6**
Vehicle Area Network	No	Yes	$0.5	-	-	**$0.5**

Description	Forward to Acounting as Extraordinary TYPE	Requested Deferral	DEP 2020	DEP 2021	DEP 2022	DEP Total
Windows PC replace	No	Yes	-	-	-	**-**
Power Electronics	No	Yes	$0.0	$0.5	$0.5	**$1.1**
POC	No	Yes	$0.3	-	-	**$0.3**
BizWAN	No	Yes	-	$0.2	$0.2	**$0.3**
Dist H&R Flooding	No	Yes	-	-	-	**-**
Trans H&R Flooding	No	Yes	$8.3	$0.8	$1.6	**$10.7**
Electric Transportation	No	No	-	-	-	**-**
TOTAL			**$235.9**	**$355.6**	**$468.9**	**$1060.3**
TOTAL EXTRAORDINARY TYPE			**$52.6**	**$65.9**	**$67.6**	**$186.1**

Duke Energy Progress
Table 1: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2018

		Current Approved		DEP Proposed			Public Staff Proposed			
Functional Category	12/31/18 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current	Accrual Rate	Accrual Amount	Difference from Current	Difference from Company
A	B	C	D	E	F	G	H	I	J	K
Steam Production Plant	3,978,949,911	3.75%	149,304,045	5.33%	212,170,895	62,866,850	4.13%	164,169,204	14,865,159	(48,001,691)
Nuclear Production Plant	8,840,958,166	2.80%	247,232,783	3.31%	292,257,258	45,024,474	3.31%	292,257,258	45,024,474	0
Hydraulic Production Plant	140,864,659	3.47%	4,891,536	3.70%	5,213,027	321,491	3.65%	5,148,380	256,845	(64,647)
Other Production Plant	3,126,769,437	4.50%	140,858,548	5.08%	158,732,404	17,873,856	5.03%	157,217,103	16,358,555	(1,515,301)
Transmission Plant	2,555,572,839	1.90%	48,603,354	2.23%	57,110,744	8,507,390	2.23%	57,110,744	8,507,390	0
Distribution Plant	6,869,268,718	2.50%	171,841,871	2.44%	167,607,654	(4,234,217)	2.32%	159,311,890	(12,529,982)	(8,295,764)
General Plant	620,468,150	5.16%	31,994,760	5.74%	35,638,485	3,643,725	4.39%	27,229,682	(4,765,078)	(8,408,803)
Land Rights	265,099,637	1.18%	3,122,714	1.18%	3,123,751	1,037	1.18%	3,123,751	1,037	0
General Plant Reserve Amortization	0	0.00%	8,985,024	0.00%	18,529,294	9,544,270	0.00%	18,529,294	9,544,270	0
Total Depreciable Plant	**26,397,951,517**	**3.06%**	**806,834,635**	**3.60%**	**950,383,512**	**143,548,877**	**3.35%**	**884,097,306**	**77,262,670**	**(66,286,206)**

I/A

Duke Energy Progress
Table 2: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2018

		Current Approved		DEP Proposed			Public Staff Proposed			
Plant	12/31/18 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current	Accrual Rate	Accrual Amount	Difference from Current	Difference from Company
A	B	C	D	E	F	G	H	I	J	K
Steam Production										
Asheville Unit 1	242,698,612	3.95%	9,593,071	4.39%	10,665,595	1,072,524	4.38%	10,620,416	1,027,346	(45,179)
Asheville Unit 2	219,865,836	2.71%	5,957,476	2.91%	6,403,586	446,110	2.90%	6,375,180	417,704	(28,406)
Mayo Unit 1	1,199,924,769	3.62%	43,416,604	5.39%	64,652,584	21,235,980	3.50%	41,964,384	(1,452,219)	(22,688,200)
Roxboro Unit 1	315,580,285	6.31%	19,900,566	6.59%	20,787,959	887,393	6.48%	20,444,106	543,540	(343,853)
Roxboro Unit 2	394,484,255	5.13%	20,239,100	5.51%	21,731,388	1,492,288	5.41%	21,322,173	1,083,073	(409,215)
Roxboro Unit 3	497,931,600	4.42%	22,027,256	6.29%	31,324,202	9,296,946	4.56%	22,725,086	697,830	(8,599,116)
Roxboro Unit 4	549,486,596	1.81%	9,971,121	4.03%	22,139,052	12,167,931	2.90%	15,921,889	5,950,769	(6,217,163)
Roxboro Common	558,977,957	3.26%	18,198,852	6.17%	34,466,529	16,267,677	4.44%	24,795,969	6,597,117	(9,670,560)
Total Steam Production	**3,978,949,911**	**3.75%**	**149,304,045**	**5.33%**	**212,170,895**	**62,866,850**	**4.13%**	**164,169,204**	**14,865,159**	**(48,001,691)**
Nuclear Production Plant										
Brunswick Unit 1	1,683,964,130	2.98%	50,230,218	3.56%	59,998,135	9,767,917	3.56%	59,998,135	9,767,917	0
Brunswick Unit 2	1,394,242,727	2.94%	41,017,928	3.30%	46,042,685	5,024,757	3.30%	46,042,685	5,024,757	0
Harris Unit 1	4,675,251,918	2.06%	96,483,034	2.15%	100,664,277	4,181,243	2.15%	100,664,277	4,181,243	0
Harris Disallowance	(551,297,291)	1.29%	(7,111,087)	1.29%	(7,132,255)	(21,168)	1.29%	(7,132,255)	(21,168)	0
Robinson Unit 2	1,638,796,682	4.06%	66,612,690	5.66%	92,684,416	26,071,726	5.66%	92,684,416	26,071,726	0
Total Nuclear Production	**8,840,958,166**	**2.80%**	**247,232,783**	**3.31%**	**292,257,258**	**45,024,474**	**3.31%**	**292,257,258**	**45,024,474**	**0**
Hydro Production Plant										
Blewett	37,702,202	3.61%	1,361,774	3.42%	1,290,195	(71,579)	3.36%	1,267,795	(93,979)	(22,400)
Marshall	13,028,861	3.60%	468,944	3.77%	491,549	22,605	3.64%	474,117	5,174	(17,432)
Tillery	32,653,770	3.03%	990,972	3.10%	1,013,552	22,580	3.04%	993,253	2,281	(20,299)
Walters	57,479,826	3.60%	2,069,846	4.21%	2,417,731	347,885	4.20%	2,413,214	343,369	(4,517)
Total Hydro Production	**140,864,659**	**3.47%**	**4,891,536**	**3.70%**	**5,213,027**	**321,491**	**3.65%**	**5,148,380**	**256,845**	**(64,647)**
Other Production Plant										
Asheville IC Turbine	113,437,289	3.12%	3,535,203	4.15%	4,707,555	1,172,352	4.15%	4,712,316	1,177,113	4,761
Blewett IC Turbines	13,460,860	2.81%	377,863	2.93%	394,098	16,235	2.74%	369,275	(8,588)	(24,823)
Darlington IC Turbine Units 1-11	45,319,458	13.74%	6,227,479	29.68%	13,453,023	7,225,544	28.67%	12,993,096	6,765,617	(459,927)
Darlington IC Turbine Units 12 & 13	84,496,862	3.93%	3,324,207	5.08%	4,293,149	968,942	5.02%	4,239,930	915,723	(53,219)
H.F. Lee IC Turbines (Wayne County Units 10-13)	181,402,477	3.51%	6,361,656	3.56%	6,452,117	90,461	3.55%	6,438,793	77,137	(13,324)
H.F. Lee IC Turbines (Wayne County Units 14)	89,090,673	3.28%	2,921,786	3.55%	3,160,196	238,410	3.55%	3,162,135	240,349	1,939
Smith IC Turbines (Richmond County)	332,213,213	5.03%	16,705,254	6.32%	20,983,440	4,278,186	6.32%	21,007,013	4,301,759	23,573
Sutton Blackstart	100,187,704	3.03%	3,039,658	3.58%	3,582,654	542,996	3.57%	3,579,679	540,021	(2,975)
Weatherspoon IC Turbines	23,678,965	2.21%	522,410	3.26%	771,917	249,507	2.91%	688,555	166,145	(83,362)

Duke Energy Progress
Table 2: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2018

		Current Approved		DEP Proposed			Public Staff Proposed			
Plant	12/31/18 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current	Accrual Rate	Accrual Amount	Difference from Current	Difference from Company
A	B	C	D	E	F	G	H	I	J	K
Smith CC Power Block 4 (Richmond County)	281,811,838	4.92%	13,877,242	5.14%	14,483,505	606,263	5.10%	14,364,519	487,277	(118,986)
Smith CC Power Block 5 (Richmond County)	435,104,111	4.70%	20,462,578	4.63%	20,159,066	(303,512)	4.60%	20,013,709	(448,868)	(145,357)
Sutton CC	539,718,713	4.03%	21,774,714	4.39%	23,715,468	1,940,754	4.36%	23,522,979	1,748,266	(192,489)
H.F. Lee CC (Wayne County)	694,626,403	4.58%	31,825,203	4.67%	32,437,628	612,425	4.63%	32,165,040	339,837	(272,588)
Total Other Production	**2,934,548,566**	**4.46%**	**130,955,252**	**5.06%**	**148,593,816**	**17,638,564**	**5.02%**	**147,257,039**	**16,301,786**	**(1,336,777)**
Solar										
Camp Lejune	18,743,440	5.03%	942,243	5.15%	965,267	23,024	5.08%	952,891	10,648	(12,376)
Fayetteville	33,006,453	5.12%	1,689,984	5.26%	1,736,946	46,962	5.17%	1,705,100	15,117	(31,846)
Elm City	52,011,085	5.17%	2,688,973	5.27%	2,738,891	49,918	5.17%	2,689,268	295	(49,623)
Warsaw	88,459,893	5.18%	4,582,097	5.31%	4,697,484	115,387	5.21%	4,612,805	30,709	(84,679)
Total Solar	**192,220,870**	**5.15%**	**9,903,296**	**5.27%**	**10,138,588**	**235,292**	**5.18%**	**9,960,064**	**56,768**	**(178,524)**
Total Production	**16,087,542,172**	**3.37%**	**542,286,912**	**4.15%**	**668,373,584**	**126,086,671**	**3.85%**	**618,791,945**	**76,505,033**	**(49,581,638)**

Duke Energy Progress
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2018

			Current Approved		DEP Proposed			Public Staff Proposed			
		12/31/18	Accrual	Accrual	Accrual	Accrual	Difference from	Accrual	Accrual	Difference from	Difference from
Account	Description	Investment	Rate	Amount	Rate	Amount	Current	Rate	Amount	Current	Company
	A	B	C	D	E	F	G	H	I	J	K
	Steam Production Plant										
311.00	Structures and Improvements										
	Asheville Unit 1	42,616,358	0.95%	404,855	1.35%	573,609	168,754	1.34%	571,470	166,615	(2,139)
	Asheville Unit 2	42,579,071	3.13%	1,332,725	3.46%	1,473,445	140,720	3.45%	1,467,740	135,015	(5,705)
	Mayo Unit 1	170,239,859	1.95%	3,319,677	2.87%	4,879,145	1,559,468	1.84%	3,124,053	(195,624)	(1,755,092)
	Roxboro Unit 1	17,139,904	2.52%	431,926	2.39%	408,845	(23,081)	2.27%	389,214	(42,712)	(19,631)
	Roxboro Unit 2	5,512,432	3.42%	188,525	3.57%	196,628	8,103	3.45%	189,943	1,418	(6,685)
	Roxboro Unit 3	37,367,402	0.87%	325,096	1.00%	372,911	47,815	0.66%	246,442	(78,654)	(126,469)
	Roxboro Unit 4	19,539,071	3.60%	703,407	5.37%	1,048,303	344,896	3.81%	744,835	41,428	(303,468)
	Roxboro Common	193,990,593	5.03%	9,757,727	7.59%	14,718,151	4,960,424	5.44%	10,545,536	787,809	(4,172,615)
	Total Structures and Improvements	*528,984,692*	*3.11%*	*16,463,938*	*4.47%*	*23,671,037*	*7,207,099*	*3.27%*	*17,279,233*	*815,295*	*(6,391,804)*
312.00	Boiler Plant Equipment										
	Asheville Unit 1	149,655,719	4.19%	6,270,575	4.76%	7,121,696	851,121	4.73%	7,081,407	810,833	(40,289)
	Asheville Unit 2	145,625,345	2.94%	4,281,385	3.22%	4,682,918	401,533	3.20%	4,660,654	379,269	(22,264)
	Mayo Unit 1	832,479,003	4.02%	33,465,656	6.06%	50,461,597	16,995,941	3.93%	32,745,505	(720,151)	(17,716,092)
	Roxboro Unit 1	212,902,506	6.56%	13,966,404	6.95%	14,793,592	827,188	6.84%	14,558,320	591,916	(235,272)
	Roxboro Unit 2	309,506,429	5.04%	15,599,124	5.50%	17,017,838	1,418,714	5.40%	16,701,850	1,102,726	(315,988)
	Roxboro Unit 3	333,830,832	4.74%	15,823,581	6.87%	22,920,294	7,096,713	4.96%	16,546,907	723,325	(6,373,387)
	Roxboro Unit 4	404,141,708	1.33%	5,375,085	3.61%	14,572,511	9,197,426	2.59%	10,472,205	5,097,120	(4,100,306)
	Roxboro Common	320,174,908	1.91%	6,115,341	5.13%	16,435,758	10,320,417	3.70%	11,846,635	5,731,294	(4,589,123)
	Total Boiler Plant Equipment	*2,708,316,451*	*3.73%*	*100,897,151*	*5.46%*	*148,006,204*	*47,109,053*	*4.23%*	*114,613,484*	*13,716,333*	*(33,392,720)*
312.10	Boiler Plant Equipment - SCR Catalyst										
	Asheville Unit 1	3,957,263	4.47%	176,890	0.00%	0	(176,890)	0.00%	0	(176,890)	0
	Asheville Unit 2	1,798,266	5.44%	97,826	0.00%	0	(97,826)	0.00%	0	(97,826)	0
	Mayo Unit 1	7,428,603	5.49%	407,830	0.00%	0	(407,830)	0.00%	0	(407,830)	0
	Roxboro Unit 1	7,925,144	1.84%	145,823	0.00%	0	(145,823)	0.00%	0	(145,823)	0
	Roxboro Unit 2	5,857,262	3.91%	229,019	0.00%	0	(229,019)	0.00%	0	(229,019)	0
	Roxboro Unit 3	6,541,925	7.92%	518,120	3.75%	245,298	(272,822)	4.64%	303,349	(214,772)	58,051
	Roxboro Unit 4	7,261,916	1.22%	88,595	0.00%	0	(88,595)	0.00%	0	(88,595)	0
	Total Boiler Plant Equipment	*40,770,378*	*4.08%*	*1,664,103*	*0.60%*	*245,298*	*(1,418,805)*	*0.74%*	*303,349*	*(1,360,754)*	*58,051*
314.00	Turbogenerator Units										
	Asheville Unit 1	18,830,228	6.65%	1,252,210	7.32%	1,378,245	126,035	7.32%	1,378,913	126,702	668
	Asheville Unit 2	13,968,641	1.12%	156,449	1.12%	155,826	(623)	1.11%	155,296	(1,153)	(530)
	Mayo Unit 1	109,608,959	3.04%	3,332,112	4.44%	4,863,907	1,531,795	2.92%	3,196,310	(135,803)	(1,667,597)

Duke Energy Progress
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2018

			Current Approved		DEP Proposed			Public Staff Proposed			
		12/31/18	Accrual	Accrual	Accrual	Accrual	Difference from	Accrual	Accrual	Difference from	Difference from
Account	Description	Investment	Rate	Amount	Rate	Amount	Current	Rate	Amount	Current	Company
	A	B	C	D	E	F	G	H	I	J	K
	Roxboro Unit 1	45,628,568	6.66%	3,038,863	6.91%	3,153,178	114,315	6.81%	3,108,301	69,439	(44,877)
	Roxboro Unit 2	44,959,643	7.10%	3,192,135	7.60%	3,418,913	226,778	7.49%	3,365,697	173,563	(53,216)
	Roxboro Unit 3	73,030,422	4.39%	3,206,036	6.30%	4,601,862	1,395,826	4.55%	3,326,111	120,076	(1,275,751)
	Roxboro Unit 4	69,565,691	3.26%	2,267,842	5.35%	3,723,176	1,455,334	3.86%	2,684,717	416,875	(1,038,459)
	Roxboro Common	458,891	2.36%	10,830	3.14%	14,425	3,595	2.26%	10,367	(463)	(4,058)
	Total Turbogenerator Units	*376,051,042*	*4.38%*	*16,456,475*	*5.67%*	*21,309,532*	*4,853,057*	*4.58%*	*17,225,711*	*769,236*	*(4,083,821)*
315.00	Accessory Electric Equipment										
	Asheville Unit 1	17,304,564	4.75%	821,967	5.18%	896,804	74,837	5.18%	896,678	74,711	(126)
	Asheville Unit 2	10,774,312	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Mayo Unit 1	66,829,604	3.55%	2,372,451	5.40%	3,607,025	1,234,574	3.50%	2,342,314	(30,137)	(1,264,711)
	Roxboro Unit 1	27,911,639	7.40%	2,065,461	7.71%	2,151,100	85,639	7.57%	2,111,745	46,284	(39,355)
	Roxboro Unit 2	24,223,049	3.55%	859,918	3.65%	883,710	23,792	3.53%	855,136	(4,782)	(28,574)
	Roxboro Unit 3	42,579,386	4.61%	1,962,910	6.84%	2,913,552	950,642	4.94%	2,105,209	142,299	(808,343)
	Roxboro Unit 4	43,547,825	3.05%	1,328,209	5.71%	2,486,371	1,158,162	4.12%	1,793,439	465,230	(692,932)
	Roxboro Common	23,722,266	5.01%	1,188,486	7.27%	1,723,633	535,147	5.24%	1,242,455	53,969	(481,178)
	Total Accessory Electric Equipment	*256,892,645*	*4.13%*	*10,599,401*	*5.71%*	*14,662,195*	*4,062,794*	*4.42%*	*11,346,976*	*747,575*	*(3,315,219)*
316.00	Miscellaneous Power Plant Equipment										
	Asheville Unit 1	10,334,481	6.45%	666,574	6.73%	695,241	28,667	6.70%	691,948	25,374	(3,293)
	Asheville Unit 2	5,120,202	1.74%	89,092	1.79%	91,397	2,305	1.79%	91,490	2,399	93
	Mayo Unit 1	13,338,741	3.89%	518,877	6.30%	840,910	322,033	4.17%	556,203	37,326	(284,707)
	Roxboro Unit 1	4,072,525	6.19%	252,089	6.91%	281,244	29,155	6.79%	276,525	24,436	(4,719)
	Roxboro Unit 2	4,425,440	3.85%	170,379	4.84%	214,299	43,920	4.74%	209,546	39,167	(4,753)
	Roxboro Unit 3	4,581,632	4.18%	191,512	5.90%	270,285	78,773	4.30%	197,068	5,556	(73,217)
	Roxboro Unit 4	5,430,383	3.83%	207,984	5.68%	308,691	100,707	4.17%	226,694	18,710	(81,997)
	Roxboro Common	20,631,299	5.46%	1,126,469	7.63%	1,574,562	448,093	5.58%	1,150,977	24,508	(423,585)
	Total Miscellaneous Power Plant Equipment	*67,934,703*	*4.74%*	*3,222,976*	*6.30%*	*4,276,629*	*1,053,653*	*5.01%*	*3,400,452*	*177,476*	*(876,177)*
	Total Steam Production Plant	**3,978,949,911**	**3.75%**	**149,304,045**	**5.33%**	**212,170,895**	**62,866,850**	**4.13%**	**164,169,204**	**14,865,159**	**(48,001,691)**
	Nuclear Production Plant										
321.00	Structures and Improvements										
	Brunswick Unit 1	423,009,419	2.62%	11,082,847	3.35%	14,175,485	3,092,638	3.35%	14,175,485	3,092,638	0
	Brunswick Unit 2	397,968,470	2.64%	10,506,368	2.89%	11,520,013	1,013,645	2.89%	11,520,013	1,013,645	0
	Harris Unit 1	1,996,266,874	1.64%	32,738,777	1.62%	32,248,496	(490,281)	1.62%	32,248,496	(490,281)	0
	Harris Disallowance	(105,862,561)	1.29%	(1,365,503)	1.29%	(1,369,567)	(4,065)	1.29%	(1,369,567)	(4,065)	0

I/A

Duke Energy Progress
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2018

			Current Approved		DEP Proposed			Public Staff Proposed			
Account	Description	12/31/18 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current	Accrual Rate	Accrual Amount	Difference from Current	Difference from Company
	A	B	C	D	E	F	G	H	I	J	K
	Robinson Unit 2	373,649,661	3.40%	12,704,088	4.37%	16,338,445	3,634,357	4.37%	16,338,445	3,634,357	0
	Total Structures and Improvements	*3,085,031,862*	*2.13%*	*65,666,577*	*2.36%*	*72,912,872*	*7,246,295*	*2.36%*	*72,912,872*	*7,246,295*	*0*
322.00	Reactor Plant Equipment										
	Brunswick Unit 1	612,117,284	2.80%	17,139,284	3.16%	19,312,794	2,173,510	3.16%	19,312,794	2,173,510	0
	Brunswick Unit 2	544,476,825	2.87%	15,626,485	3.14%	17,115,022	1,488,537	3.14%	17,115,022	1,488,537	0
	Harris Unit 1	1,075,559,612	2.73%	29,362,777	2.68%	28,850,918	(511,859)	2.68%	28,850,918	(511,859)	0
	Harris Disallowance	(132,409,445)	1.29%	(1,707,926)	1.29%	(1,713,010)	(5,084)	1.29%	(1,713,010)	(5,084)	0
	Robinson Unit 2	462,756,240	3.40%	15,733,712	4.21%	19,464,027	3,730,315	4.21%	19,464,027	3,730,315	0
	Total Reactor Plant Equipment	*2,562,500,516*	*2.97%*	*76,154,332*	*3.24%*	*83,029,751*	*6,875,418*	*3.24%*	*83,029,751*	*6,875,418*	*0*
323.00	Turbogenerator Units										
	Brunswick Unit 1	285,997,062	3.06%	8,751,510	4.13%	11,823,008	3,071,498	4.13%	11,823,008	3,071,498	0
	Brunswick Unit 2	172,548,284	3.32%	5,728,603	3.73%	6,442,418	713,815	3.73%	6,442,418	713,815	0
	Harris Unit 1	535,687,360	2.48%	13,285,047	3.24%	17,371,808	4,086,761	3.24%	17,371,808	4,086,761	0
	Harris Disallowance	(610,466)	1.29%	(7,874)	1.29%	(7,898)	(23)	1.29%	(7,898)	(23)	0
	Robinson Unit 2	333,276,804	5.04%	16,797,151	8.07%	26,899,155	10,102,004	8.07%	26,899,155	10,102,004	0
	Total Turbogenerator Units	*1,326,899,045*	*3.36%*	*44,554,436*	*4.71%*	*62,528,491*	*17,974,055*	*4.71%*	*62,528,491*	*17,974,055*	*0*
324.00	Accessory Electric Equipment										
	Brunswick Unit 1	161,647,775	3.77%	6,094,121	4.22%	6,821,086	726,965	4.22%	6,821,086	726,965	0
	Brunswick Unit 2	210,342,927	3.20%	6,730,974	4.01%	8,431,189	1,700,215	4.01%	8,431,189	1,700,215	0
	Harris Unit 1	820,436,970	1.86%	15,260,128	1.99%	16,303,928	1,043,800	1.99%	16,303,928	1,043,800	0
	Harris Disallowance	(256,837,665)	1.29%	(3,312,904)	1.29%	(3,322,766)	(9,862)	1.29%	(3,322,766)	(9,862)	0
	Robinson Unit 2	279,070,966	3.84%	10,716,325	6.43%	17,942,656	7,226,331	6.43%	17,942,656	7,226,331	0
	Total Accessory Electric Equipment	*1,214,660,973*	*2.92%*	*35,488,644*	*3.80%*	*46,176,093*	*10,687,450*	*3.80%*	*46,176,093*	*10,687,450*	*0*
325.00	Miscellaneous Power Plant Equipment										
	Brunswick Unit 1	201,192,590	3.56%	7,162,456	3.91%	7,865,762	703,306	3.91%	7,865,762	703,306	0
	Brunswick Unit 2	68,906,220	3.52%	2,425,499	3.68%	2,534,043	108,544	3.68%	2,534,043	108,544	0
	Harris Unit 1	247,301,102	2.36%	5,836,306	2.38%	5,889,127	52,821	2.38%	5,889,127	52,821	0
	Harris Disallowance	(55,577,154)	1.29%	(716,880)	1.29%	(719,014)	(2,134)	1.29%	(719,014)	(2,134)	0
	Robinson Unit 2	190,043,011	5.61%	10,661,413	6.34%	12,040,133	1,378,720	6.34%	12,040,133	1,378,720	0
	Total Miscellaneous Power Plant Equipment	*651,865,769*	*3.89%*	*25,368,794*	*4.24%*	*27,610,051*	*2,241,257*	*4.24%*	*27,610,051*	*2,241,257*	*0*
	Total Nuclear Production Plant	**8,840,958,166**	**2.80%**	**247,232,783**	**3.31%**	**292,257,258**	**45,024,474**	**3.31%**	**292,257,258**	**45,024,474**	**0**
	Hydraulic Production Plant										

Duke Energy Progress
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2018

					DEP Proposed			Public Staff Proposed			
			Current Approved				Difference			Difference	Difference
		12/31/18	Accrual	Accrual	Accrual	Accrual	from	Accrual	Accrual	from	from
Account	Description	Investment	Rate	Amount	Rate	Amount	Current	Rate	Amount	Current	Company
	A	B	C	D	E	F	G	H	I	J	K
331.00	Structures and Improvements										
	Blewett	6,620,301	2.59%	171,466	2.83%	187,401	15,935	2.78%	183,804	12,338	(3,597)
	Marshall	1,523,287	6.77%	103,127	7.03%	107,146	4,019	6.89%	104,936	1,809	(2,210)
	Tillery	6,634,057	2.37%	157,227	3.05%	202,328	45,101	3.00%	198,746	41,518	(3,582)
	Walters	3,472,324	3.15%	109,378	3.24%	112,577	3,199	3.24%	112,586	3,208	9
	Total Structures and Improvements	*18,249,969*	*2.97%*	*541,198*	*3.34%*	*609,452*	*68,254*	*3.29%*	*600,072*	*58,874*	*(9,380)*
332.00	Reservoirs, Dams, and Waterways										
	Blewett	8,275,323	2.22%	183,712	1.94%	160,135	(23,577)	1.88%	155,171	(28,541)	(4,964)
	Marshall	4,071,208	3.30%	134,350	3.52%	143,440	9,090	3.39%	138,206	3,856	(5,234)
	Tillery	6,796,645	1.82%	123,699	1.62%	110,074	(13,625)	1.56%	106,022	(17,677)	(4,052)
	Walters	34,543,362	2.87%	991,394	3.46%	1,195,944	204,550	3.45%	1,192,063	200,669	(3,881)
	Total Reservoirs, Dams, and Waterways	*53,686,539*	*2.67%*	*1,433,155*	*3.00%*	*1,609,593*	*176,438*	*2.96%*	*1,591,462*	*158,306*	*(18,131)*
333.00	Water Wheels, Turbines, and Generators										
	Blewett	13,436,525	4.84%	650,328	4.00%	536,807	(113,521)	3.94%	528,862	(121,466)	(7,945)
	Marshall	6,041,207	2.98%	180,028	3.14%	189,470	9,442	3.00%	181,347	1,319	(8,123)
	Tillery	14,142,265	3.86%	545,891	3.75%	530,595	(15,296)	3.69%	521,584	(24,307)	(9,011)
	Walters	4,456,121	3.14%	139,922	3.49%	155,664	15,742	3.49%	155,330	15,408	(334)
	Total Water Wheels, Turbines, and Generator	*38,076,119*	*3.98%*	*1,516,169*	*3.71%*	*1,412,536*	*(103,633)*	*3.64%*	*1,387,123*	*(129,047)*	*(25,413)*
334.00	Accessory Electric Equipment										
	Blewett	7,543,722	3.81%	287,416	4.49%	338,949	51,533	4.43%	334,299	46,883	(4,650)
	Marshall	1,179,516	3.44%	40,575	3.41%	40,208	(367)	3.27%	38,608	(1,967)	(1,600)
	Tillery	3,853,242	3.40%	131,010	3.57%	137,612	6,602	3.50%	134,798	3,787	(2,814)
	Walters	13,242,973	5.62%	744,255	6.47%	856,757	112,502	6.47%	856,405	112,150	(352)
	Total Accessory Electric Equipment	*25,819,454*	*4.66%*	*1,203,257*	*5.32%*	*1,373,526*	*170,269*	*5.28%*	*1,364,109*	*160,853*	*(9,417)*
335.00	Miscellaneous Power Plant Equipment										
	Blewett	1,826,330	3.77%	68,853	3.66%	66,903	(1,950)	3.60%	65,660	(3,193)	(1,243)
	Marshall	200,697	5.23%	10,496	5.44%	10,921	425	5.32%	10,674	177	(247)
	Tillery	1,227,560	2.70%	33,144	2.68%	32,943	(201)	2.62%	32,104	(1,040)	(839)
	Walters	1,756,787	4.83%	84,853	5.51%	96,765	11,912	5.51%	96,806	11,953	41
	Total Miscellaneous Power Plant Equipment	*5,011,373*	*3.94%*	*197,346*	*4.14%*	*207,532*	*10,186*	*4.10%*	*205,244*	*7,898*	*(2,288)*
336.00	Roads, Railroads, and Bridges										
	Marshall	12,947	2.84%	368	2.81%	364	(4)	2.68%	347	(20)	(17)

Duke Energy Progress
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As of December 31, 2018

			Current Approved		DEP Proposed			Public Staff Proposed			
Account	Description	12/31/18 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current	Accrual Rate	Accrual Amount	Difference from Current	Difference from Company
	A	B	C	D	E	F	G	H	I	J	K
	Walters	8,258	0.52%	43	0.29%	24	(19)	0.29%	24	(19)	(0)
	Total Roads, Railroads, and Bridges	*21,205*	*1.94%*	*411*	*1.83%*	*388*	*(23)*	*1.75%*	*371*	*(39)*	*(17)*
	Total Hydraulic Production Plant	**140,864,659**	**3.47%**	**4,891,536**	**3.70%**	**5,213,027**	**321,491**	**3.65%**	**5,148,380**	**256,845**	**(64,647)**
	Other Production Plant										
341.00	Structures and Improvements										
	Asheville IC Turbine	31,762,836	2.95%	937,004	3.07%	975,677	38,673	3.07%	973,986	36,982	(1,691)
	Blewett IC Turbines	979,563	1.36%	13,322	1.14%	11,136	(2,186)	0.95%	9,258	(4,065)	(1,878)
	Darlington IC Turbine Units 1-11	362,283	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Darlington IC Turbine Units 12 & 13	8,403,246	0.15%	12,605	0.83%	69,646	57,041	0.77%	64,785	52,180	(4,861)
	H.F. Lee IC Turbines (Wayne County Units 1	9,013,914	2.66%	239,770	2.82%	254,463	14,693	2.83%	254,892	15,121	429
	H.F. Lee IC Turbines (Wayne County Units 1	1,356,820	2.74%	37,177	2.97%	40,347	3,170	2.97%	40,283	3,107	(64)
	Smith IC Turbines (Richmond County)	19,344,678	2.89%	559,061	2.99%	579,000	19,939	3.00%	579,928	20,867	928
	Sutton Blackstart	11,574,793	0.00%	0	2.00%	231,353	231,353	2.00%	231,219	231,219	(134)
	Weatherspoon IC Turbines	3,568,977	1.51%	53,892	2.59%	92,356	38,464	2.23%	79,462	25,571	(12,894)
	Smith CC Power Block 4 (Richmond County	47,694,243	0.90%	429,248	0.92%	440,153	10,905	0.88%	417,408	(11,840)	(22,745)
	Smith CC Power Block 5 (Richmond County	40,103,160	2.89%	1,158,981	3.07%	1,232,177	73,196	3.04%	1,219,621	60,639	(12,556)
	Sutton CC	13,462,879	3.54%	476,586	3.81%	512,673	36,087	3.78%	509,046	32,460	(3,627)
	H.F. Lee CC (Wayne County)	25,476,302	2.38%	606,336	2.79%	711,705	105,369	2.76%	702,602	96,266	(9,103)
	Total Structures and Improvements	*213,103,694*	*2.12%*	*4,523,982*	*2.42%*	*5,150,686*	*626,704*	*2.38%*	*5,082,489*	*558,508*	*(68,197)*
341.20	Structures and Improvements - Solar										
	Camp Lejune	26,131	5.03%	1,314	5.00%	1,307	(7)	4.94%	1,291	(23)	(16)
	Fayetteville	3,958	5.12%	203	5.15%	204	1	5.06%	200	(2)	(4)
	Elm City	3,926	5.17%	203	5.17%	203	0	5.08%	199	(4)	(4)
	Total Structures and Improvements - Solar	*34,014*	*5.06%*	*1,720*	*5.04%*	*1,714*	*(6)*	*4.97%*	*1,691*	*(29)*	*(23)*
342.00	Fuel Holders, Producers, and Accessories										
	Asheville IC Turbine	5,115,723	2.25%	115,104	2.90%	148,602	33,498	2.90%	148,328	33,225	(274)
	Blewett IC Turbines	413,480	1.86%	7,691	1.75%	7,229	(462)	1.57%	6,491	(1,200)	(738)
	Darlington IC Turbine Units 1-11	5,048,367	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Darlington IC Turbine Units 12 & 13	7,243,963	1.32%	95,620	1.50%	108,699	13,079	1.44%	104,411	8,791	(4,288)
	H.F. Lee IC Turbines (Wayne County Units 1	7,363,988	2.77%	203,982	2.98%	219,470	15,488	2.99%	219,857	15,874	387
	H.F. Lee IC Turbines (Wayne County Units 1	1,461,179	2.99%	43,689	2.98%	43,476	(213)	2.97%	43,427	(262)	(49)
	Smith IC Turbines (Richmond County)	8,473,790	3.01%	255,061	3.15%	267,152	12,091	3.15%	267,101	12,040	(51)
	Sutton Blackstart	5,990,885	2.93%	175,533	3.14%	188,103	12,570	3.14%	188,015	12,482	(88)

Duke Energy Progress
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As of December 31, 2018

			Current Approved		DEP Proposed			Public Staff Proposed			
							Difference			Difference	Difference
		12/31/18	Accrual	Accrual	Accrual	Accrual	from	Accrual	Accrual	from	from
Account	Description	Investment	Rate	Amount	Rate	Amount	Current	Rate	Amount	Current	Company
	A	B	C	D	E	F	G	H	I	J	K
	Weatherspoon IC Turbines	1,651,095	5.30%	87,508	8.49%	140,115	52,607	8.10%	133,684	46,176	(6,431)
	Smith CC Power Block 4 (Richmond County	13,523,523	2.74%	370,545	3.00%	405,772	35,227	2.95%	398,941	28,397	(6,831)
	Smith CC Power Block 5 (Richmond County	22,575,250	2.92%	659,197	3.11%	702,612	43,415	3.07%	693,755	34,558	(8,857)
	Sutton CC	19,656,538	2.93%	575,937	4.25%	835,790	259,853	4.21%	828,099	252,162	(7,691)
	H.F. Lee CC (Wayne County)	25,423,310	3.07%	780,496	3.33%	845,788	65,292	3.29%	836,826	56,331	(8,962)
	Total Fuel Holders, Producers, and Accessorie	*123,941,092*	*2.72%*	*3,370,363*	*3.16%*	*3,912,808*	*542,445*	*3.12%*	*3,868,935*	*498,573*	*(43,873)*
343.00	Prime Movers										
	Asheville IC Turbine	51,871,873	3.18%	1,649,526	5.08%	2,634,563	985,037	5.09%	2,642,300	992,774	7,737
	Blewett IC Turbines	8,455,727	3.76%	317,935	3.98%	336,664	18,729	3.75%	317,231	(705)	(19,433)
	Darlington IC Turbine Units 1-11	22,476,732	19.72%	4,432,411	43.45%	9,767,204	5,334,793	42.07%	9,455,903	5,023,492	(311,301)
	Darlington IC Turbine Units 12 & 13	39,502,462	5.32%	2,101,531	7.34%	2,901,267	799,736	7.28%	2,874,274	772,743	(26,993)
	H.F. Lee IC Turbines (Wayne County Units 1	121,712,253	3.82%	4,649,408	3.89%	4,737,903	88,495	3.88%	4,726,096	76,687	(11,807)
	H.F. Lee IC Turbines (Wayne County Units 1	61,526,437	3.46%	2,128,815	3.78%	2,326,209	197,394	3.78%	2,328,698	199,884	2,489
	Smith IC Turbines (Richmond County)	230,437,633	5.46%	12,581,895	6.46%	14,883,340	2,301,445	6.47%	14,907,718	2,325,823	24,378
	Sutton Blackstart	65,019,559		2,314,696	4.08%	2,651,182	336,486	4.07%	2,648,158	333,461	(3,024)
	Weatherspoon IC Turbines	12,638,465	0.19%	24,013	0.68%	86,525	62,512	0.30%	37,790	13,776	(48,735)
	Smith CC Power Block 4 (Richmond County	114,272,117	5.72%	6,536,365	7.04%	8,046,676	1,510,311	6.97%	7,969,547	1,433,182	(77,129)
	Smith CC Power Block 5 (Richmond County	236,173,460	3.84%	9,069,061	3.96%	9,344,070	275,009	3.92%	9,251,522	182,461	(92,548)
	Sutton CC	361,361,293	3.56%	12,864,462	4.18%	15,105,488	2,241,026	4.14%	14,964,471	2,100,009	(141,017)
	H.F. Lee CC (Wayne County)	443,686,011	3.96%	17,569,966	4.29%	19,052,498	1,482,532	4.25%	18,849,725	1,279,759	(202,773)
	Total Prime Movers	*1,769,134,021*	*4.31%*	*76,240,084*	*5.19%*	*91,873,589*	*15,633,505*	*5.14%*	*90,973,432*	*14,733,348*	*(900,157)*
343.10	Prime Movers - Rotable Parts										
	Smith CC Power Block 4 (Richmond County	39,318,265	13.49%	5,304,034	12.31%	4,840,705	(463,329)	12.31%	4,840,705	(463,329)	0
	Smith CC Power Block 5 (Richmond County	44,987,833	15.17%	6,824,654	13.28%	5,974,679	(849,975)	13.28%	5,974,679	(849,975)	0
	Sutton CC	29,483,115	14.68%	4,328,121	12.14%	3,577,906	(750,215)	12.14%	3,577,906	(750,215)	0
	H.F. Lee CC (Wayne County)	56,542,096	14.68%	8,300,380	12.48%	7,057,740	(1,242,640)	12.48%	7,057,740	(1,242,640)	0
	Total Prime Movers - Rotable Parts	*170,331,308*	*14.53%*	*24,757,189*	*12.59%*	*21,451,030*	*(3,306,159)*	*12.59%*	*21,451,030*	*(3,306,159)*	*0*
344.00	Generators										
	Asheville IC Turbine	7,769,953	2.83%	219,890	3.01%	233,653	13,763	3.01%	233,986	14,096	333
	Blewett IC Turbines	1,988,285	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Darlington IC Turbine Units 1-11	12,472,615	11.27%	1,405,664	24.83%	3,097,560	1,691,896	23.94%	2,985,842	1,580,178	(111,718)
	Darlington IC Turbine Units 12 & 13	17,131,838	3.92%	671,568	4.29%	735,468	63,900	4.24%	725,840	54,272	(9,628)
	H.F. Lee IC Turbines (Wayne County Units 1	22,068,501	2.90%	639,987	2.87%	632,402	(7,585)	2.86%	631,132	(8,854)	(1,270)
	H.F. Lee IC Turbines (Wayne County Units 1	13,021,303	2.85%	371,107	3.00%	390,823	19,716	3.00%	390,367	19,260	(456)
	Smith IC Turbines (Richmond County)	37,046,161	5.43%	2,011,607	10.08%	3,735,595	1,723,988	10.08%	3,734,666	1,723,060	(929)

Duke Energy Progress
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2018

			Current Approved		DEP Proposed			Public Staff Proposed			
							Difference			Difference	Difference
		12/31/18	Accrual	Accrual	Accrual	Accrual	from	Accrual	Accrual	from	from
Account	Description	Investment	Rate	Amount	Rate	Amount	Current	Rate	Amount	Current	Company
	A	B	C	D	E	F	G	H	I	J	K
	Sutton Blackstart	2,145,711	2.88%	61,796	2.77%	59,357	(2,439)	2.76%	59,323	(2,473)	(34)
	Weatherspoon IC Turbines	2,095,744	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Smith CC Power Block 4 (Richmond County	40,449,075	1.07%	432,805	0.00%	0	(432,805)	0.00%	0	(432,805)	0
	Smith CC Power Block 5 (Richmond County	31,516,637	2.90%	913,982	3.00%	946,600	32,618	2.97%	934,984	21,002	(11,616)
	Sutton CC	44,450,493	2.88%	1,280,174	3.00%	1,335,598	55,424	2.97%	1,321,864	41,690	(13,734)
	H.F. Lee CC (Wayne County)	55,122,184	3.07%	1,692,251	3.17%	1,748,825	56,574	3.14%	1,729,506	37,255	(19,319)
	Total Generators	*287,278,501*	*3.38%*	*9,700,831*	*4.50%*	*12,915,881*	*3,215,050*	*4.44%*	*12,747,510*	*3,046,679*	*(168,371)*
344.20	Generators - Solar										
	Camp Lejune	15,956,192	5.03%	802,596	5.15%	822,344	19,748	5.09%	811,672	9,076	(10,672)
	Fayetteville	32,469,235	5.12%	1,662,425	5.26%	1,708,709	46,284	5.17%	1,677,467	15,043	(31,242)
	Elm City	51,863,632	5.17%	2,681,350	5.27%	2,731,170	49,820	5.17%	2,681,697	347	(49,473)
	Warsaw	87,181,903	5.18%	4,516,023	5.31%	4,629,736	113,713	5.21%	4,546,493	30,471	(83,243)
	Total Generators - Solar	*187,470,961*	*5.15%*	*9,662,394*	*5.28%*	*9,891,959*	*229,565*	*5.18%*	*9,717,330*	*54,936*	*(174,629)*
345.00	Accessory Electric Equipment										
	Asheville IC Turbine	13,502,430	3.67%	495,539	4.07%	549,433	53,894	4.06%	548,142	52,603	(1,291)
	Blewett IC Turbines	1,418,891	1.18%	16,743	0.88%	12,494	(4,249)	0.70%	9,946	(6,797)	(2,548)
	Darlington IC Turbine Units 1-11	4,869,111	7.99%	389,042	8.43%	410,605	21,563	7.71%	375,484	(13,558)	(35,121)
	Darlington IC Turbine Units 12 & 13	10,782,808	3.73%	402,199	4.02%	433,757	31,558	3.96%	427,194	24,995	(6,563)
	H.F. Lee IC Turbines (Wayne County Units 1	19,926,915	3.01%	599,800	2.89%	576,702	(23,098)	2.89%	575,646	(24,154)	(1,056)
	H.F. Lee IC Turbines (Wayne County Units 1	10,599,165	2.94%	311,615	3.03%	321,295	9,680	3.03%	321,220	9,604	(75)
	Smith IC Turbines (Richmond County)	29,257,399	3.02%	883,573	3.06%	894,076	10,503	3.05%	893,344	9,771	(732)
	Sutton Blackstart	13,595,340	3.15%	428,253	2.79%	379,136	(49,117)	2.79%	379,360	(48,893)	224
	Weatherspoon IC Turbines	3,003,206	8.62%	258,876	10.98%	329,700	70,824	10.53%	316,246	57,370	(13,454)
	Smith CC Power Block 4 (Richmond County	21,653,205	3.18%	688,572	3.34%	723,937	35,365	3.30%	714,050	25,478	(9,887)
	Smith CC Power Block 5 (Richmond County	51,327,924	3.06%	1,570,634	3.16%	1,621,061	50,427	3.13%	1,605,255	34,621	(15,806)
	Sutton CC	62,940,671	3.15%	1,982,631	3.20%	2,012,729	30,098	3.16%	1,989,626	6,994	(23,103)
	H.F. Lee CC (Wayne County)	76,581,370	3.25%	2,488,895	3.31%	2,531,320	42,425	3.27%	2,504,948	16,054	(26,372)
	Total Accessory Electric Equipment	*319,458,437*	*3.29%*	*10,516,374*	*3.38%*	*10,796,245*	*279,871*	*3.34%*	*10,660,461*	*144,088*	*(135,784)*
345.20	Accessory Electric Equipment - Solar										
	Camp Lejune	2,761,117	5.01%	138,332	5.13%	141,616	3,284	5.07%	139,927	1,595	(1,689)
	Fayetteville	533,261	5.13%	27,356	5.26%	28,033	677	5.14%	27,433	76	(600)
	Elm City	133,458	5.17%	6,900	5.24%	6,990	90	5.13%	6,852	(48)	(138)
	Warsaw	1,258,878	5.17%	65,084	5.30%	66,731	1,647	5.19%	65,313	229	(1,418)
	Total Accessory Electric Equipment - Solar	*4,686,715*	*5.07%*	*237,672*	*5.19%*	*243,370*	*5,698*	*5.11%*	*239,525*	*1,853*	*(3,845)*

Duke Energy Progress
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2018

			Current Approved		DEP Proposed			Public Staff Proposed			
Account	Description	12/31/18 Investment	Accrual Rate	Accrual Amount	Accrual Rate	Accrual Amount	Difference from Current	Accrual Rate	Accrual Amount	Difference from Current	Difference from Company
	A	B	C	D	E	F	G	H	I	J	K
346.00	Miscellaneous Power Plant Equipment										
	Asheville IC Turbine	3,414,473	3.46%	118,141	4.85%	165,627	47,486	4.85%	165,574	47,433	(53)
	Blewett IC Turbines	204,915	10.82%	22,172	12.97%	26,575	4,403	12.86%	26,350	4,178	(225)
	Darlington IC Turbine Units 1-11	90,350	0.40%	361	196.63%	177,654	177,293	194.65%	175,866	175,505	(1,788)
	Darlington IC Turbine Units 12 & 13	1,432,545	2.84%	40,684	3.09%	44,312	3,628	3.03%	43,426	2,742	(886)
	H.F. Lee IC Turbines (Wayne County Units 1	1,316,905	2.18%	28,709	2.37%	31,177	2,468	2.37%	31,171	2,462	(6)
	H.F. Lee IC Turbines (Wayne County Units 1	1,125,769	2.61%	29,383	3.38%	38,046	8,663	3.39%	38,140	8,757	94
	Smith IC Turbines (Richmond County)	7,653,552	5.41%	414,057	8.16%	624,277	210,220	8.16%	624,255	210,198	(22)
	Sutton Blackstart	1,861,416		59,379	3.95%	73,523	14,144	3.95%	73,605	14,225	82
	Weatherspoon IC Turbines	721,478	13.60%	98,121	17.08%	123,221	25,100	16.82%	121,373	23,252	(1,848)
	Smith CC Power Block 4 (Richmond County	4,901,411	2.36%	115,673	0.54%	26,262	(89,411)	0.49%	23,867	(91,806)	(2,395)
	Smith CC Power Block 5 (Richmond County	8,419,845	3.16%	266,067	4.01%	337,867	71,800	3.97%	333,893	67,826	(3,974)
	Sutton CC	8,363,725	3.19%	266,803	4.01%	335,284	68,481	3.97%	331,968	65,165	(3,316)
	H.F. Lee CC (Wayne County)	11,795,130	3.28%	386,880	4.15%	489,752	102,872	4.10%	483,692	96,811	(6,060)
	Total Miscellaneous Power Plant Equipment	*51,301,514*	*3.60%*	*1,846,430*	*4.86%*	*2,493,577*	*647,147*	*4.82%*	*2,473,180*	*626,750*	*(20,397)*
346.20	Miscellaneous Power Plant Equipment - Solar										
	Elm City	10,069	5.17%	521	5.24%	528	7	5.16%	520	(1)	(8)
	Warsaw	19,111	5.18%	990	5.32%	1,017	27	5.23%	999	9	(18)
	Total Miscellaneous Power Plant Equipment -	*29,181*	*5.18%*	*1,511*	*5.29%*	*1,545*	*34*	*5.20%*	*1,518*	*8*	*(27)*
	Total Other Production Plant	**3,126,769,437**	**4.50%**	**140,858,548**	**5.08%**	**158,732,404**	**17,873,856**	**5.03%**	**157,217,103**	**16,358,555**	**(1,515,301)**
	Total Production Plant	**16,087,542,172**	**3.37%**	**542,286,912**	**4.15%**	**668,373,584**	**126,086,671**	**3.85%**	**618,791,945**	**76,505,033**	**(49,581,638)**
	Transmission Plant										
352.00	Structures and Improvements	90,193,204	1.78%	1,605,439	1.80%	1,622,028	16,589	1.80%	1,622,028	16,589	0
353.00	Station Equipment	1,070,174,832	1.90%	20,333,322	2.21%	23,628,452	3,295,130	2.21%	23,628,452	3,295,130	0
354.00	Towers and Fixtures	78,936,365	1.35%	1,065,641	1.19%	936,307	(129,334)	1.19%	936,307	(129,334)	0
355.00	Poles and Fixtures	743,280,242	2.22%	16,500,821	2.56%	19,031,917	2,531,096	2.56%	19,031,917	2,531,096	0
356.00	Overhead Conductors and Devices	551,039,389	1.56%	8,596,214	2.07%	11,383,033	2,786,819	2.07%	11,383,033	2,786,819	0
357.00	Underground Conduit	32,286	2.30%	743	1.73%	559	(184)	1.73%	559	(184)	0
358.00	Underground Conductors and Devices	21,603,999	2.30%	496,892	2.33%	504,195	7,303	2.33%	504,195	7,303	0
359.00	Roads and Trails	312,523	1.37%	4,282	1.36%	4,253	(29)	1.36%	4,253	(29)	0
	Total Transmission Plant	**2,555,572,839**	**1.90%**	**48,603,354**	**2.23%**	**57,110,744**	**8,507,390**	**2.23%**	**57,110,744**	**8,507,390**	**0**

Duke Energy Progress
Table 3: Summary of Depreciation Rates and Annual Accrual Amounts
As of December 31, 2018

			Current Approved		DEP Proposed			Public Staff Proposed			
		12/31/18	Accrual	Accrual	Accrual	Accrual	Difference from	Accrual	Accrual	Difference from	Difference from
Account	Description	Investment	Rate	Amount	Rate	Amount	Current	Rate	Amount	Current	Company
	A	B	C	D	E	F	G	H	I	J	K
	Distribution Plant										
361.00	Structures and Improvements	127,079,158	1.52%	1,931,603	1.59%	2,021,366	89,763	1.59%	2,021,366	89,763	0
362.00	Station Equipment	683,055,387	2.33%	15,915,191	2.24%	15,332,138	(583,053)	2.24%	15,332,138	(583,053)	0
364.00	Poles, Towers, and Fixtures	855,785,431	3.95%	33,803,525	3.92%	33,556,194	(247,331)	3.15%	26,969,475	(6,834,049)	(6,586,719)
365.00	Overhead Conductors and Devices	1,208,423,459	2.15%	25,981,104	2.06%	24,922,045	(1,059,059)	2.06%	24,922,045	(1,059,059)	0
366.00	Underground Conduit	199,779,067	2.26%	4,515,007	2.37%	4,725,775	210,768	2.21%	4,423,872	(91,135)	(301,903)
367.00	Underground Conductors and Devices	1,134,635,170	1.76%	19,969,579	1.62%	18,411,036	(1,558,543)	1.62%	18,411,036	(1,558,543)	0
368.00	Line Transformers	1,131,254,324	2.54%	28,733,860	2.46%	27,806,592	(927,268)	2.46%	27,806,592	(927,268)	0
369.00	Services	681,775,180	1.96%	13,362,794	1.59%	10,868,784	(2,494,010)	1.47%	10,028,527	(3,334,267)	(840,257)
370.00	Metering Equipment	51,889,324	3.41%	1,769,426	2.05%	1,063,840	(705,586)	2.05%	1,063,840	(705,586)	0
370.01	Meters	142,517,522	0.00%	7,479,748		7,007,351	(472,397)	0.00%	7,007,351	(472,397)	0
370.02	Meters - Utility of the Future	69,710,613	6.41%	4,468,450	6.66%	4,645,856	177,406	5.85%	4,078,971	(389,479)	(566,885)
371.00	Installations on Customers' Premises	318,551,649	1.15%	3,663,344	1.38%	4,405,748	742,404	1.38%	4,405,748	742,404	0
373.00	Street Lighting and Signal Systems	264,812,434	3.87%	10,248,241	4.85%	12,840,929	2,592,688	4.85%	12,840,929	2,592,688	0
	Total Distribution Plant	**6,869,268,718**	**2.50%**	**171,841,871**	**2.44%**	**167,607,654**	**(4,234,217)**	**2.32%**	**159,311,890**	**(12,529,982)**	**(8,295,764)**
	General Plant										
390.00	Structures and Improvements	156,446,136	2.42%	3,785,996	2.43%	3,805,402	19,406	2.43%	3,805,402	19,406	0
391.00	Office Furniture and Equipment										
	Fully Accrued	10,200,215	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Amortized	14,520,609	5.00%	726,030	6.67%	968,950	242,920	4.59%	666,321	(59,710)	(302,629)
	Total Account 391	*24,720,824*	*2.94%*	*726,030*	*3.92%*	*968,950*	*242,920*	*2.70%*	*666,321*	*(59,710)*	*(302,629)*
391.10	Office Furniture and Equipment - EDP	61,586,228	12.50%	7,698,279	12.50%	7,696,591	(1,688)	12.50%	7,696,591	(1,688)	0
392.00	Transportation Equipment	69,975,818	10.29%	7,200,512	6.42%	4,493,909	(2,706,603)	6.42%	4,493,909	(2,706,603)	0
393.00	Stores Equipment	2,059,933	5.00%	102,997	5.00%	102,894	(103)	5.00%	102,894	(103)	0
394.00	Tools, Shop, and Garage Equipment	90,247,659	5.00%	4,512,383	5.00%	4,508,503	(3,880)	5.00%	4,508,503	(3,880)	0
395.00	Laboratory Equipment	6,739,789	6.67%	449,544	6.67%	449,309	(235)	6.67%	449,309	(235)	0
396.00	Power Operated Equipment	5,679,686	5.99%	340,213	7.26%	412,343	72,130	7.26%	412,343	72,130	0
397.00	Communication Equipment										
	Fully Accrued	59,435,956	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Amortized	120,535,863	5.00%	6,026,793	10.00%	12,049,716	6,022,923	3.27%	3,943,542	(2,083,251)	(8,106,174)
	Total Account 397	*179,971,819*	*3.35%*	*6,026,793*	*6.70%*	*12,049,716*	*6,022,923*	*2.19%*	*3,943,542*	*(2,083,251)*	*(8,106,174)*

Duke Energy Progress
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As of December 31, 2018

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	A	B	C	D	E	F	G	H	I	J	K
398.00	Miscellaneous Equipment	23,040,258	5.00%	1,152,013	5.00%	1,150,868	(1,145)	5.00%	1,150,868	(1,145)	0
	Total General Plant	**620,468,150**	**5.16%**	**31,994,760**	**5.74%**	**35,638,485**	**3,643,725**	**4.39%**	**27,229,682**	**(4,765,078)**	**(8,408,803)**
	Total Transmission, Distribution, and General I	**10,045,309,708**	**2.51%**	**252,439,985**	**2.59%**	**260,356,883**	**7,916,898**	**2.43%**	**243,652,315**	**(8,787,670)**	**(16,704,568)**
	Depreciable Land Rights										
310.00	Land Rights										
	Asheville Unit 1	919,202	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Mayo Unit 1	3,577,118	0.78%	27,902	0.97%	34,725	6,823	0.97%	34,725	6,823	0
	Roxboro Unit 1	1,827,203	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Roxboro Unit 3	3,037,934	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Total Account 310	9,361,457	0.30%	27,902	0.37%	34,725	6,823	0.37%	34,725	6,823	0
320.00	Land Rights										
	Harris Unit 1	49,809,293	1.21%	602,692	1.21%	601,134	(1,558)	1.21%	601,134	(1,558)	0
	Robinson Unit 2	315,920	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Total Account 320	50,125,213	1.20%	602,692	1.20%	601,134	(1,558)	1.20%	601,134	(1,558)	0
320.10	Rights of Way										
	Brunswick Unit 1	9,724	0.89%	87	0.93%	90	3	0.93%	90	3	0
	Brunswick Unit 2	51,363	0.17%	87	0.17%	88	1	0.17%	88	1	0
	Robinson Unit 2	6,141	0.00%	0	0.00%	0	0	0.00%	0	0	0
	Total Account 320.10	67,228	0.26%	174	0.26%	178	4	0.26%	178	4	0
330.00	Land Rights										
	Walters	80,797	2.73%	2,206	2.67%	2,160	(46)	2.67%	2,160	(46)	0
	Total Account 330	80,797	2.73%	2,206	2.67%	2,160	(46)	2.67%	2,160	(46)	0
330.10	Rights of Way										
	Blewett	9,598	2.22%	213	2.03%	195	(18)	2.03%	195	(18)	0
	Marshall	3,729	2.82%	105	2.63%	98	(7)	2.63%	98	(7)	0
	Tillery	19,764	1.41%	279	1.32%	261	(18)	1.32%	261	(18)	0
	Walters	33,333	2.71%	903	2.66%	887	(16)	2.66%	887	(16)	0
	Total Account 330.1	66,424	2.26%	1,500	2.17%	1,441	(59)	2.17%	1,441	(59)	0

Duke Energy Progress
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As of December 31, 2018

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	A	B	C	D	E	F	G	H	I	J	K
340.00	Land Rights										
	H.F. Lee IC Turbines (Wayne County Units 1	2,048,655	2.51%	51,421	2.40%	49,114	(2,307)	2.40%	49,114	(2,307)	0
	Total Account 340	2,048,655	2.51%	51,421	2.40%	49,114	(2,307)	2.40%	49,114	(2,307)	0
340.10	Rights of Way										
	H.F. Lee IC Turbines (Wayne County Units 1	2,532,367	2.76%	69,893	2.67%	67,739	(2,154)	2.67%	67,739	(2,154)	0
	Total Account 340.1	2,532,367	2.76%	69,893	2.67%	67,739	(2,154)	2.67%	67,739	(2,154)	0
350.10	Rights of Way	176,749,824	1.15%	2,032,623	1.15%	2,039,608	6,985	1.15%	2,039,608	6,985	0
360.00	Land Rights	107,521	1.49%	1,602	1.48%	1,586	(16)	1.48%	1,586	(16)	0
360.10	Rights of Way	23,908,367	1.28%	306,027	1.25%	298,919	(7,108)	1.25%	298,919	(7,108)	0
389.10	Rights of Way	51,783	51.51%	26,674	52.42%	27,147	473	52.42%	27,147	473	0
	Total Depreciable Land Rights	**265,099,637**	**1.18%**	**3,122,714**	**1.18%**	**3,123,751**	**1,037**	**1.18%**	**3,123,751**	**1,037**	**0**
	Reserve Adjustment for Amortization										
391.00	Office Furniture and Equipment			2,640,179		3,426,096	785,917		3,426,096	785,917	0
393.00	Stores Equipment			172,193		152,417	(19,776)		152,417	(19,776)	0
394.00	Tools, Shop, and Garage Equipment			2,051,679		2,277,657	225,978		2,277,657	225,978	0
395.00	Laboratory Equipment			(53,710)		(79,664)	(25,954)		(79,664)	(25,954)	0
397.00	Communication Equipment			2,599,760		11,355,498	8,755,738		11,355,498	8,755,738	0
398.00	Miscellaneous Equipment			1,574,923		1,397,290	(177,633)		1,397,290	(177,633)	0
	Total Reserve Adjustment for Amortization			**8,985,024**	**0.00%**	**18,529,294**	**9,544,270**	**0.00%**	**18,529,294**	**9,544,270**	**0**
	Total Depreciable Plant	**26,397,951,517**		**806,834,635**	**3.60%**	**950,383,512**	**143,548,877**	**3.35%**	**884,097,306**	**77,262,670**	**(66,286,206)**

Duke Energy Progress
Table 4: Calculation of Depreciation Rates
As of December 31, 2018

Account	Description	12/31/18 Investment	12/31/18 Book Reserve	Percent Reserve	Future Net Salvage Percent	Net Plant to be Recovered	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D=C/B	E	F	G	H	I
	Steam Production Plant								
311.00	Structures and Improvements								
	Asheville Unit 1	42,616,358	39,177,778	91.93%	-4%	5,143,234	9.0	1.34%	571,470
	Asheville Unit 2	42,579,071	31,072,574	72.98%	-4%	13,209,660	9.0	3.45%	1,467,740
	Mayo Unit 1	170,239,859	126,127,393	74.09%	-4%	50,922,061	16.3	1.84%	3,124,053
	Roxboro Unit 1	17,139,904	14,127,970	82.43%	-4%	3,697,530	9.5	2.27%	389,214
	Roxboro Unit 2	5,512,432	3,928,468	71.27%	-4%	1,804,461	9.5	3.45%	189,943
	Roxboro Unit 3	37,367,402	35,337,975	94.57%	-4%	3,524,124	14.3	0.66%	246,442
	Roxboro Unit 4	19,539,071	9,595,015	49.11%	-4%	10,725,619	14.4	3.81%	744,835
	Roxboro Common	193,990,593	49,894,500	25.72%	-4%	151,855,717	14.4	5.44%	10,545,536
	Total Structures and Improvements	*528,984,692*	*309,261,673*	*58.46%*		*240,882,406*	*13.9*	*3.27%*	*17,279,233*
312.00	Boiler Plant Equipment								
	Asheville Unit 1	149,655,719	93,325,565	62.36%	-4%	62,316,384	8.8	4.73%	7,081,407
	Asheville Unit 2	145,625,345	110,436,602	75.84%	-4%	41,013,757	8.8	3.20%	4,660,654
	Mayo Unit 1	832,479,003	354,948,282	42.64%	-4%	510,829,881	15.6	3.93%	32,745,505
	Roxboro Unit 1	212,902,506	87,482,059	41.09%	-4%	133,936,547	9.2	6.84%	14,558,320
	Roxboro Unit 2	309,506,429	168,229,667	54.35%	-4%	153,657,020	9.2	5.40%	16,701,850
	Roxboro Unit 3	333,830,832	118,836,753	35.60%	-4%	228,347,313	13.8	4.96%	16,546,907
	Roxboro Unit 4	404,141,708	275,790,947	68.24%	-4%	144,516,430	13.8	2.59%	10,472,205
	Roxboro Common	320,174,908	168,313,679	52.57%	-4%	164,668,225	13.9	3.70%	11,846,635
	Total Boiler Plant Equipment	*2,708,316,451*	*1,377,363,553*	*50.86%*		*1,439,285,556*	*12.6*	*4.23%*	*114,613,484*
312.10	Boiler Plant Equipment - SCR Catalyst								
	Asheville Unit 1	3,957,263	4,500,630	113.73%	0%	(543,367)	0.0	0.00%	0
	Asheville Unit 2	1,798,266	1,961,047	109.05%	0%	(162,782)	0.0	0.00%	0
	Mayo Unit 1	7,428,603	7,594,648	102.24%	0%	(166,045)	3.9		0
	Roxboro Unit 1	7,925,144	8,427,153	106.33%	0%	(502,009)	0.0	0.00%	0
	Roxboro Unit 2	5,857,262	6,103,037	104.20%	0%	(245,775)	0.0	0.00%	0
	Roxboro Unit 3	6,541,925	4,994,846	76.35%	0%	1,547,079	5.1	4.64%	303,349
	Roxboro Unit 4	7,261,916	8,154,038	112.28%	0%	(892,122)	3.3		0
	Total Boiler Plant Equipment	*40,770,378*	*41,735,399*	*102.37%*		*(965,020)*	*(3.2)*	*0.74%*	*303,349*
314.00	Turbogenerator Units								
	Asheville Unit 1	18,830,228	7,586,897	40.29%	-4%	11,996,540	8.7	7.32%	1,378,913
	Asheville Unit 2	13,968,641	13,145,255	94.11%	-4%	1,382,131	8.9	1.11%	155,296
	Mayo Unit 1	109,608,959	65,409,412	59.68%	-4%	48,583,905	15.2	2.92%	3,196,310
	Roxboro Unit 1	45,628,568	18,857,340	41.33%	-4%	28,596,370	9.2	6.81%	3,108,301
	Roxboro Unit 2	44,959,643	15,793,614	35.13%	-4%	30,964,415	9.2	7.49%	3,365,697
	Roxboro Unit 3	73,030,422	30,051,305	41.15%	-4%	45,900,334	13.8	4.55%	3,326,111
	Roxboro Unit 4	69,565,691	35,567,696	51.13%	-4%	36,780,623	13.7	3.86%	2,684,717
	Roxboro Common	458,891	337,291	73.50%	-4%	139,956	13.5	2.26%	10,367
	Total Turbogenerator Units	*376,051,042*	*186,748,811*	*49.66%*		*204,344,273*	*11.9*	*4.58%*	*17,225,711*
315.00	Accessory Electric Equipment								
	Asheville Unit 1	17,304,564	10,105,982	58.40%	-4%	7,890,765	8.8	5.18%	896,678
	Asheville Unit 2	10,774,312	11,377,112	105.59%	-4%	(171,827)	0.0	0.00%	0
	Mayo Unit 1	66,829,604	32,728,460	48.97%	-4%	36,774,329	15.7	3.50%	2,342,314
	Roxboro Unit 1	27,911,639	9,388,873	33.64%	-4%	19,639,231	9.3	7.57%	2,111,745
	Roxboro Unit 2	24,223,049	17,239,203	71.17%	-4%	7,952,769	9.3	3.53%	855,136
	Roxboro Unit 3	42,579,386	15,020,156	35.28%	-4%	29,262,405	13.9	4.94%	2,105,209
	Roxboro Unit 4	43,547,825	20,360,939	46.76%	-4%	24,928,799	13.9	4.12%	1,793,439
	Roxboro Common	23,722,266	7,276,792	30.67%	-4%	17,394,365	14.0	5.24%	1,242,455
	Total Accessory Electric Equipment	*256,892,645*	*123,497,516*	*48.07%*		*143,670,834*	*12.7*	*4.42%*	*11,346,976*
316.00	Miscellaneous Power Plant Equipment								
	Asheville Unit 1	10,334,481	4,727,909	45.75%	-4%	6,019,951	8.7	6.70%	691,948
	Asheville Unit 2	5,120,202	4,538,194	88.63%	-4%	786,816	8.6	1.79%	91,490
	Mayo Unit 1	13,338,741	5,584,869	41.87%	-4%	8,287,422	14.9	4.17%	556,203
	Roxboro Unit 1	4,072,525	1,719,045	42.21%	-4%	2,516,381	9.1	6.79%	276,525
	Roxboro Unit 2	4,425,440	2,695,586	60.91%	-4%	1,906,872	9.1	4.74%	209,546
	Roxboro Unit 3	4,581,632	2,143,896	46.79%	-4%	2,621,002	13.3	4.30%	197,068

Duke Energy Progress
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	A	B	C	D=C/B	E	F	G	H	I
	Roxboro Unit 4	5,430,383	2,700,578	49.73%	-4%	2,947,021	13.0	4.17%	226,694
	Roxboro Common	20,631,299	5,918,365	28.69%	-4%	15,538,185	13.5	5.58%	1,150,977
	Total Miscellaneous Power Plant Equipment	*67,934,703*	*30,028,440*	*44.20%*		*40,623,651*	*11.9*	*5.01%*	*3,400,452*
	Total Steam Production Plant	**3,978,949,911**	**2,068,635,392**	**51.99%**		**2,067,841,700**	**12.6**	**4.13%**	**164,169,204**
	Nuclear Production Plant								
321.00	Structures and Improvements								
	Brunswick Unit 1	423,009,419	182,352,007	43.11%	-1%	244,887,506	17.3	3.35%	14,155,347
	Brunswick Unit 2	397,968,470	223,090,544	56.06%	-1%	178,857,611	15.5	2.90%	11,539,201
	Harris Unit 1	1,996,266,874	1,204,989,357	60.36%	-2%	831,202,855	25.8	1.61%	32,217,165
	Harris Disallowance	(105,862,561)	(67,742,934)	63.99%	0%	(38,119,627)	27.8	1.29%	(1,369,567)
	Robinson Unit 2	373,649,661	190,668,370	51.03%	-1%	186,717,788	11.4	4.38%	16,378,753
	Total Structures and Improvements	*3,085,031,862*	*1,733,357,343*	*56.19%*		*1,403,546,132*	*19.2*	*2.36%*	*72,920,899*
322.00	Reactor Plant Equipment								
	Brunswick Unit 1	612,117,284	299,468,246	48.92%	-1%	318,770,211	16.5	3.16%	19,319,407
	Brunswick Unit 2	544,476,825	293,189,240	53.85%	-1%	256,732,353	15.0	3.14%	17,115,490
	Harris Unit 1	1,075,559,612	425,966,772	39.60%	-2%	671,104,032	23.3	2.68%	28,802,748
	Harris Disallowance	(132,409,445)	(84,730,657)	63.99%	0%	(47,678,788)	27.8	1.29%	(1,713,010)
	Robinson Unit 2	462,756,240	249,630,881	53.94%	-1%	217,752,922	11.2	4.20%	19,442,225
	Total Reactor Plant Equipment	*2,562,500,516*	*1,183,524,482*	*46.19%*		*1,416,680,730*	*17.1*	*3.24%*	*82,966,860*
323.00	Turbogenerator Units								
	Brunswick Unit 1	285,997,062	101,762,273	35.58%	-1%	187,094,760	15.8	4.14%	11,841,440
	Brunswick Unit 2	172,548,284	83,648,310	48.48%	-1%	90,625,457	14.1	3.72%	6,427,337
	Harris Unit 1	535,687,360	148,284,568	27.68%	-2%	398,116,540	22.9	3.25%	17,385,002
	Harris Disallowance	(610,466)	(390,646)	63.99%	0%	(219,820)	27.8	1.29%	(7,898)
	Robinson Unit 2	333,276,804	41,912,529	12.58%	-1%	294,697,043	11.0	8.04%	26,790,640
	Total Turbogenerator Units	*1,326,899,045*	*375,217,034*	*28.28%*		*970,313,979*	*15.5*	*4.71%*	*62,436,522*
324.00	Accessory Electric Equipment								
	Brunswick Unit 1	161,647,775	48,960,985	30.29%	-1%	114,303,267	16.8	4.21%	6,803,766
	Brunswick Unit 2	210,342,927	83,854,412	39.87%	-1%	128,591,944	15.3	4.00%	8,404,702
	Harris Unit 1	820,436,970	447,858,632	54.59%	-2%	388,987,077	23.9	1.98%	16,275,610
	Harris Disallowance	(256,837,665)	(164,354,016)	63.99%	0%	(92,483,649)	27.8	1.29%	(3,322,766)
	Robinson Unit 2	279,070,966	77,699,673	27.84%	-1%	204,162,003	11.4	6.42%	17,908,948
	Total Accessory Electric Equipment	*1,214,660,973*	*494,019,687*	*40.67%*		*743,560,643*	*16.1*	*3.79%*	*46,070,260*
325.00	Miscellaneous Power Plant Equipment								
	Brunswick Unit 1	201,192,590	72,402,768	35.99%	-1%	130,801,748	16.6	3.92%	7,879,623
	Brunswick Unit 2	68,906,220	31,605,240	45.87%	-1%	37,990,042	15.0	3.68%	2,532,669
	Harris Unit 1	247,301,102	110,487,995	44.68%	-2%	141,759,129	24.1	2.38%	5,882,122
	Harris Disallowance	(55,577,154)	(35,564,599)	63.99%	0%	(20,012,555)	27.8	1.29%	(719,014)
	Robinson Unit 2	190,043,011	57,228,953	30.11%	-1%	134,714,488	11.2	6.33%	12,028,079
	Total Miscellaneous Power Plant Equipment	*651,865,769*	*236,160,357*	*36.23%*		*425,252,852*	*15.4*	*4.23%*	*27,603,480*
	Total Nuclear Production Plant	**8,840,958,166**	**4,022,278,903**	**45.50%**		**4,959,354,336**	**17.0**	**3.30%**	**291,998,020**
	Hydraulic Production Plant								
331.00	Structures and Improvements								
	Blewett	6,620,301	2,221,068	33.55%	-31%	6,451,526	35.1	2.78%	183,804
	Marshall	1,523,287	36,589	2.40%	-14%	1,699,957	16.2	6.89%	104,936
	Tillery	6,634,057	1,449,284	21.85%	-27%	6,975,968	35.1	3.00%	198,746
	Walters	3,472,324	1,969,353	56.72%	-6%	1,711,310	15.2	3.24%	112,586
	Total Structures and Improvements	*18,249,969*	*5,676,294*	*31.10%*		*16,838,763*	*28.1*	*3.29%*	*600,072*
332.00	Reservoirs, Dams, and Waterways								
	Blewett	8,275,323	5,471,755	66.12%	-31%	5,368,918	34.6	1.88%	155,171
	Marshall	4,071,208	2,374,604	58.33%	-14%	2,266,573	16.4	3.39%	138,206
	Tillery	6,796,645	4,942,178	72.71%	-27%	3,689,561	34.8	1.56%	106,022

Duke Energy Progress
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	A	B	C	D=C/B	E	F	G	H	I
	Walters	34,543,362	18,258,190	52.86%	-6%	18,357,774	15.4	3.45%	1,192,063
	Total Reservoirs, Dams, and Waterways	*53,686,539*	*31,046,729*	*57.83%*		*29,682,826*	*18.7*	*2.96%*	*1,591,462*
333.00	Water Wheels, Turbines, and Generators								
	Blewett	13,436,525	255,189	1.90%	-31%	17,346,660	32.8	3.94%	528,862
	Marshall	6,041,207	4,039,831	66.87%	-14%	2,847,145	15.7	3.00%	181,347
	Tillery	14,142,265	1,061,347	7.50%	-27%	16,899,329	32.4	3.69%	521,584
	Walters	4,456,121	2,409,069	54.06%	-6%	2,314,420	14.9	3.49%	155,330
	Total Water Wheels, Turbines, and Generat	*38,076,119*	*7,765,436*	*20.39%*		*39,407,554*	*28.4*	*3.64%*	*1,387,123*
334.00	Accessory Electric Equipment								
	Blewett	7,543,722	(213,543)	-2.83%	-31%	10,095,820	30.2	4.43%	334,299
	Marshall	1,179,516	773,248	65.56%	-14%	571,401	14.8	3.27%	38,608
	Tillery	3,853,242	944,048	24.50%	-27%	3,949,570	29.3	3.50%	134,798
	Walters	13,242,973	1,362,762	10.29%	-6%	12,674,790	14.8	6.47%	856,405
	Total Accessory Electric Equipment	*25,819,454*	*2,866,514*	*11.10%*		*27,291,580*	*20.0*	*5.28%*	*1,364,109*
335.00	Miscellaneous Power Plant Equipment								
	Blewett	1,826,330	422,693	23.14%	-31%	1,969,799	30.0	3.60%	65,660
	Marshall	200,697	66,551	33.16%	-14%	162,243	15.2	5.32%	10,674
	Tillery	1,227,560	602,303	49.07%	-27%	956,698	29.8	2.62%	32,104
	Walters	1,756,787	448,826	25.55%	-6%	1,413,368	14.6	5.51%	96,806
	Total Miscellaneous Power Plant Equipment	*5,011,373*	*1,540,374*	*30.74%*		*4,502,108*	*21.9*	*4.10%*	*205,244*
336.00	Roads, Railroads, and Bridges								
	Marshall	12,947	9,238	71.35%	-14%	5,522	15.9	2.68%	347
	Walters	8,258	8,473	102.60%	-6%	281	11.7	0.29%	24
	Total Roads, Railroads, and Bridges	*21,205*	*17,711*	*83.52%*		*5,802*	*15.6*	*1.75%*	*371*
	Total Hydraulic Production Plant	**140,864,659**	**48,913,058**	**34.72%**		**117,728,632**	**22.9**	**3.65%**	**5,148,380**
	Other Production Plant								
341.00	Structures and Improvements								
	Asheville IC Turbine	31,762,836	15,086,579	47.50%	-3%	17,629,142	18.1	3.07%	973,986
	Blewett IC Turbines	979,563	987,420	100.80%	-6%	50,916	5.5	0.95%	9,258
	Darlington IC Turbine Units 1-11	362,283	1,161,265	320.54%	-6%	(777,246)	0.0	0.00%	0
	Darlington IC Turbine Units 12 & 13	8,403,246	7,799,625	92.82%	-6%	1,107,815	17.1	0.77%	64,785
	H.F. Lee IC Turbines (Wayne County Units	9,013,914	4,506,042	49.99%	-4%	4,868,429	19.1	2.83%	254,892
	H.F. Lee IC Turbines (Wayne County Units	1,356,820	323,439	23.84%	-4%	1,087,654	27.0	2.97%	40,283
	Smith IC Turbines (Richmond County)	19,344,678	7,843,041	40.54%	-2%	11,888,531	20.5	3.00%	579,928
	Sutton Blackstart	11,574,793	4,616,347	39.88%	-9%	8,000,177	34.6	2.00%	231,219
	Weatherspoon IC Turbines	3,568,977	3,833,880	107.42%	-19%	413,203	5.2	2.23%	79,462
	Smith CC Power Block 4 (Richmond Count	47,694,243	40,526,455	84.97%	-3%	8,598,615	20.6	0.88%	417,408
	Smith CC Power Block 5 (Richmond Count	40,103,160	7,907,269	19.72%	-7%	35,003,112	28.7	3.04%	1,219,621
	Sutton CC	13,462,879	(1,895,584)	-14.08%	-2%	15,627,720	30.7	3.78%	509,046
	H.F. Lee CC (Wayne County)	25,476,302	7,358,309	28.88%	-5%	19,391,809	27.6	2.76%	702,602
	Total Structures and Improvements	*213,103,694*	*100,054,088*	*46.95%*		*122,889,878*	*24.2*	*2.38%*	*5,082,489*
341.20	Structures and Improvements - Solar								
	Camp Lejune	26,131	1,617	6.19%	-8%	26,604	20.6	4.94%	1,291
	Fayetteville	3,958	248	6.27%	-9%	4,066	20.3	5.06%	200
	Elm City	3,926	248	6.31%	-13%	4,189	21.0	5.08%	199
	Total Structures and Improvements - Solar	*34,014*	*2,113*	*6.21%*		*34,858*	*20.6*	*4.97%*	*1,691*
342.00	Fuel Holders, Producers, and Accessories								
	Asheville IC Turbine	5,115,723	2,495,453	48.78%	-3%	2,773,742	18.7	2.90%	148,328
	Blewett IC Turbines	413,480	403,237	97.52%	-6%	35,052	5.4	1.57%	6,491
	Darlington IC Turbine Units 1-11	5,048,367	5,817,173	115.23%	-6%	(465,903)	0.0	0.00%	0
	Darlington IC Turbine Units 12 & 13	7,243,963	5,872,288	81.06%	-6%	1,806,313	17.3	1.44%	104,411
	H.F. Lee IC Turbines (Wayne County Units	7,363,988	3,459,288	46.98%	-4%	4,199,260	19.1	2.99%	219,857
	H.F. Lee IC Turbines (Wayne County Units	1,461,179	360,131	24.65%	-4%	1,159,495	26.7	2.97%	43,427
	Smith IC Turbines (Richmond County)	8,473,790	3,354,658	39.59%	-2%	5,288,608	19.8	3.15%	267,101

Duke Energy Progress
Table 4: Calculation of Depreciation Rates
As of December 31, 2018

Account	Description	12/31/18 Investment	12/31/18 Book Reserve	Percent Reserve	Future Net Salvage Percent	Net Plant to be Recovered	Remaining Life	Total Annual Rate	Total Annual Accrual
	A	B	C	D=C/B	E	F	G	H	I
	Sutton Blackstart	5,990,885	137,567	2.30%	-9%	6,392,498	34.0	3.14%	188,015
	Weatherspoon IC Turbines	1,651,095	1,242,908	75.28%	-19%	721,895	5.4	8.10%	133,684
	Smith CC Power Block 4 (Richmond Count	13,523,523	5,631,253	41.64%	-3%	8,297,976	20.8	2.95%	398,941
	Smith CC Power Block 5 (Richmond Count	22,575,250	4,383,495	19.42%	-7%	19,772,022	28.5	3.07%	693,755
	Sutton CC	19,656,538	(5,290,149)	-26.91%	-2%	25,339,817	30.6	4.21%	828,099
	H.F. Lee CC (Wayne County)	25,423,310	2,091,783	8.23%	-5%	24,602,693	29.4	3.29%	836,826
	Total Fuel Holders, Producers, and Accessor	*123,941,092*	*29,959,084*	*24.17%*		*99,923,468*	*25.8*	*3.12%*	*3,868,935*
343.00	Prime Movers								
	Asheville IC Turbine	51,871,873	8,773,161	16.91%	-3%	44,654,868	16.9	5.09%	2,642,300
	Blewett IC Turbines	8,455,727	7,408,641	87.62%	-6%	1,554,430	4.9	3.75%	317,231
	Darlington IC Turbine Units 1-11	22,476,732	9,641,480	42.90%	-6%	14,183,855	1.5	42.07%	9,455,903
	Darlington IC Turbine Units 12 & 13	39,502,462	(379,217)	-0.96%	-6%	42,251,826	14.7	7.28%	2,874,274
	H.F. Lee IC Turbines (Wayne County Units	121,712,253	48,127,557	39.54%	-4%	78,453,186	16.6	3.88%	4,726,096
	H.F. Lee IC Turbines (Wayne County Units	61,526,437	14,386,219	23.38%	-4%	49,601,275	21.3	3.78%	2,328,698
	Smith IC Turbines (Richmond County)	230,437,633	(28,820,222)	-12.51%	-2%	263,866,608	17.7	6.47%	14,907,718
	Sutton Blackstart	65,019,559	1,224,776	1.88%	-9%	69,646,543	26.3	4.07%	2,648,158
	Weatherspoon IC Turbines	12,638,465	14,847,046	117.48%	-19%	192,727	5.1	0.30%	37,790
	Smith CC Power Block 4 (Richmond Count	114,272,117	(21,766,797)	-19.05%	-3%	139,467,077	17.5	6.97%	7,969,547
	Smith CC Power Block 5 (Richmond Count	236,173,460	45,471,509	19.25%	-7%	207,234,094	22.4	3.92%	9,251,522
	Sutton CC	361,361,293	12,434,111	3.44%	-2%	356,154,408	23.8	4.14%	14,964,471
	H.F. Lee CC (Wayne County)	443,686,011	30,441,659	6.86%	-5%	435,428,653	23.1	4.25%	18,849,725
	Total Prime Movers	*1,769,134,021*	*141,789,923*	*8.01%*		*1,702,689,550*	*18.7*	*5.14%*	*90,973,432*
343.10	Prime Movers - Rotable Parts								
	Smith CC Power Block 4 (Richmond Count	39,318,265	3,453,628	8.78%	40%	20,137,331	4.2	12.19%	4,794,603
	Smith CC Power Block 5 (Richmond Count	44,987,833	7,894,446	17.55%	40%	19,098,254	3.2	13.27%	5,968,204
	Sutton CC	29,483,115	5,468,284	18.55%	40%	12,221,585	3.4	12.19%	3,594,584
	H.F. Lee CC (Wayne County)	56,542,096	6,820,315	12.06%	40%	27,104,942	3.8	12.62%	7,132,880
	Total Prime Movers - Rotable Parts	*170,331,308*	*23,636,673*	*13.88%*		*78,562,112*	*3.7*	*12.62%*	*21,490,270*
344.00	Generators								
	Asheville IC Turbine	7,769,953	3,627,517	46.69%	-3%	4,375,535	18.7	3.01%	233,986
	Blewett IC Turbines	1,988,285	2,204,189	110.86%	-6%	(96,607)	0.0	0.00%	0
	Darlington IC Turbine Units 1-11	12,472,615	8,742,209	70.09%	-6%	4,478,763	1.5	23.94%	2,985,842
	Darlington IC Turbine Units 12 & 13	17,131,838	5,675,300	33.13%	-6%	12,484,449	17.2	4.24%	725,840
	H.F. Lee IC Turbines (Wayne County Units	22,068,501	10,644,166	48.23%	-4%	12,307,075	19.5	2.86%	631,132
	H.F. Lee IC Turbines (Wayne County Units	13,021,303	2,807,071	21.56%	-4%	10,735,084	27.5	3.00%	390,367
	Smith IC Turbines (Richmond County)	37,046,161	(38,773,572)	-104.66%	-2%	76,560,656	20.5	10.08%	3,734,666
	Sutton Blackstart	2,145,711	274,377	12.79%	-9%	2,064,447	34.8	2.76%	59,323
	Weatherspoon IC Turbines	2,095,744	2,565,954	122.44%	-19%	(72,019)	0.0	0.00%	0
	Smith CC Power Block 4 (Richmond Count	40,449,075	62,933,029	155.59%	-3%	(21,270,482)	0.0	0.00%	0
	Smith CC Power Block 5 (Richmond Count	31,516,637	6,327,771	20.08%	-7%	27,395,031	29.3	2.97%	934,984
	Sutton CC	44,450,493	4,229,533	9.52%	-2%	41,109,970	31.1	2.97%	1,321,864
	H.F. Lee CC (Wayne County)	55,122,184	5,647,199	10.24%	-5%	52,231,094	30.2	3.14%	1,729,506
	Total Generators	*287,278,501*	*76,904,743*	*26.77%*		*222,302,997*	*17.4*	*4.44%*	*12,747,510*
344.20	Generators - Solar								
	Camp Lejune	15,956,192	1,973,252	12.37%	-8%	15,259,435	18.8	5.09%	811,672
	Fayetteville	32,469,235	4,022,825	12.39%	-9%	31,368,641	18.7	5.17%	1,677,467
	Elm City	51,863,632	5,776,472	11.14%	-13%	52,829,432	19.7	5.17%	2,681,697
	Warsaw	87,181,903	10,880,666	12.48%	-10%	85,019,427	18.7	5.21%	4,546,493
	Total Generators - Solar	*187,470,961*	*22,653,215*	*12.08%*		*184,476,935*	*19.0*	*5.18%*	*9,717,330*
345.00	Accessory Electric Equipment								
	Asheville IC Turbine	13,502,430	3,492,810	25.87%	-3%	10,414,693	19.0	4.06%	548,142
	Blewett IC Turbines	1,418,891	1,450,318	102.21%	-6%	53,707	5.4	0.70%	9,946
	Darlington IC Turbine Units 1-11	4,869,111	4,598,032	94.43%	-6%	563,226	1.5	7.71%	375,484
	Darlington IC Turbine Units 12 & 13	10,782,808	4,167,477	38.65%	-6%	7,262,299	17.0	3.96%	427,194
	H.F. Lee IC Turbines (Wayne County Units	19,926,915	9,556,455	47.96%	-4%	11,167,537	19.4	2.89%	575,646
	H.F. Lee IC Turbines (Wayne County Units	10,599,165	2,350,198	22.17%	-4%	8,672,934	27.0	3.03%	321,220
	Smith IC Turbines (Richmond County)	29,257,399	11,618,321	39.71%	-2%	18,224,226	20.4	3.05%	893,344
	Sutton Blackstart	13,595,340	1,958,624	14.41%	-9%	12,860,297	33.9	2.79%	379,360

Duke Energy Progress
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	Weatherspoon IC Turbines	3,003,206	1,866,086	62.14%	-19%	1,707,730	5.4	10.53%	316,246
	Smith CC Power Block 4 (Richmond Count	21,653,205	7,093,541	32.76%	-3%	15,209,261	21.3	3.30%	714,050
	Smith CC Power Block 5 (Richmond Count	51,327,924	8,850,051	17.24%	-7%	46,070,828	28.7	3.13%	1,605,255
	Sutton CC	62,940,671	3,515,905	5.59%	-2%	60,683,579	30.5	3.16%	1,989,626
	H.F. Lee CC (Wayne County)	76,581,370	6,263,965	8.18%	-5%	74,146,473	29.6	3.27%	2,504,948
	Total Accessory Electric Equipment	*319,458,437*	*66,781,781*	*20.90%*		*267,036,791*	*25.0*	*3.34%*	*10,660,461*
345.20	Accessory Electric Equipment - Solar								
	Camp Lejune	2,761,117	351,375	12.73%	-8%	2,630,632	18.8	5.07%	139,927
	Fayetteville	533,261	68,266	12.80%	-9%	512,988	18.7	5.14%	27,433
	Elm City	133,458	16,509	12.37%	-13%	134,298	19.6	5.13%	6,852
	Warsaw	1,258,878	163,411	12.98%	-10%	1,221,355	18.7	5.19%	65,313
	Total Accessory Electric Equipment - Solar	*4,686,715*	*599,561*	*12.79%*		*4,499,274*	*18.8*	*5.11%*	*239,525*
346.00	Miscellaneous Power Plant Equipment								
	Asheville IC Turbine	3,414,473	900,837	26.38%	-3%	2,616,070	15.8	4.85%	165,574
	Blewett IC Turbines	204,915	80,191	39.13%	-6%	137,018	5.2	12.86%	26,350
	Darlington IC Turbine Units 1-11	90,350	(168,029)	-185.98%	-6%	263,800	1.5	194.65%	175,866
	Darlington IC Turbine Units 12 & 13	1,432,545	806,305	56.28%	-6%	712,193	16.4	3.03%	43,426
	H.F. Lee IC Turbines (Wayne County Units	1,316,905	889,548	67.55%	-4%	480,033	15.4	2.37%	31,171
	H.F. Lee IC Turbines (Wayne County Units	1,125,769	408,002	36.24%	-4%	762,798	20.0	3.39%	38,140
	Smith IC Turbines (Richmond County)	7,653,552	(2,805,709)	-36.66%	-2%	10,612,331	17.0	8.16%	624,255
	Sutton Blackstart	1,861,416	26,901	1.45%	-9%	2,002,043	27.2	3.95%	73,605
	Weatherspoon IC Turbines	721,478	215,281	29.84%	-19%	643,278	5.3	16.82%	121,373
	Smith CC Power Block 4 (Richmond Count	4,901,411	4,552,021	92.87%	-3%	496,432	20.8	0.49%	23,867
	Smith CC Power Block 5 (Richmond Count	8,419,845	1,797,141	21.34%	-7%	7,212,094	21.6	3.97%	333,893
	Sutton CC	8,363,725	630,158	7.53%	-2%	7,900,842	23.8	3.97%	331,968
	H.F. Lee CC (Wayne County)	11,795,130	1,356,717	11.50%	-5%	11,028,170	22.8	4.10%	483,692
	Total Miscellaneous Power Plant Equipment	*51,301,514*	*8,689,364*	*16.94%*		*44,867,101*	*18.1*	*4.82%*	*2,473,180*
346.20	Miscellaneous Power Plant Equipment - Solar								
	Elm City	10,069	467	4.64%	-13%	10,911	21.0	5.16%	520
	Warsaw	19,111	547	2.86%	-10%	20,475	20.5	5.23%	999
	Total Miscellaneous Power Plant Equipment	*29,181*	*1,015*	*3.48%*		*31,386*	*20.7*	*5.20%*	*1,518*
	Total Other Production Plant	**3,126,769,437**	**471,071,560**	**15.07%**		**2,727,314,350**	**17.3**	**5.03%**	**157,256,343**
	Total Production Plant	**16,087,542,172**	**6,610,898,913**	**41.09%**		**9,872,239,018**	**16.0**	**3.85%**	**618,571,948**
	Transmission Plant								
352.00	Structures and Improvements	90,193,204	30,731,591	34.07%	-10%	68,480,933	42.2	1.80%	1,622,771
353.00	Station Equipment	1,070,174,832	233,041,480	21.78%	-15%	997,659,577	42.2	2.21%	23,641,222
354.00	Towers and Fixtures	78,936,365	46,268,549	58.61%	-20%	48,455,088	51.8	1.19%	935,426
355.00	Poles and Fixtures	743,280,242	262,890,321	35.37%	-40%	777,702,017	40.9	2.56%	19,014,719
356.00	Overhead Conductors and Devices	551,039,389	187,315,525	33.99%	-40%	584,139,620	51.3	2.07%	11,386,737
357.00	Underground Conduit	32,286	(584)	-1.81%	0%	32,870	58.8	1.73%	559
358.00	Underground Conductors and Devices	21,603,999	1,688,307	7.81%	0%	19,915,692	39.5	2.33%	504,195
359.00	Roads and Trails	312,523	68,523	21.93%	0%	244,000	57.4	1.36%	4,251
	Total Transmission Plant	**2,555,572,839**	**762,003,713**	**29.82%**		**2,496,629,797**	**43.7**	**2.23%**	**57,109,881**
	Distribution Plant								
361.00	Structures and Improvements	127,079,158	48,130,054	37.87%	-15%	98,010,977	48.5	1.59%	2,020,845
362.00	Station Equipment	683,055,387	199,280,175	29.17%	-15%	586,233,520	38.2	2.25%	15,346,427
364.00	Poles, Towers, and Fixtures	855,785,431	618,419,612	72.26%	-75%	879,204,892	32.6	3.15%	26,969,475
365.00	Overhead Conductors and Devices	1,208,423,459	617,880,131	51.13%	-30%	953,070,366	38.2	2.06%	24,949,486
366.00	Underground Conduit	199,779,067	72,884,435	36.48%	-10%	146,872,538	33.2	2.21%	4,423,872
367.00	Underground Conductors and Devices	1,134,635,170	622,088,309	54.83%	-5%	569,278,619	30.9	1.62%	18,423,256
368.00	Line Transformers	1,131,254,324	379,239,615	33.52%	-5%	808,577,425	29.1	2.46%	27,786,166
369.00	Services	681,775,180	370,866,150	54.40%	-15%	413,175,307	41.2	1.47%	10,028,527
370.00	Metering Equipment	51,889,324	28,415,375	54.76%	-10%	28,662,881	26.9	2.05%	1,065,535

Duke Energy Progress
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370.01	Meters	142,517,522	81,602,020	57.26%	-5%	68,041,378	9.7	4.92%	7,014,575
370.02	Meters - Utility of the Future	69,710,613	2,407,594	3.45%	0%	67,303,019	16.5	5.85%	4,078,971
371.00	Installations on Customers' Premises	318,551,649	252,936,350	79.40%	-10%	97,470,464	22.1	1.38%	4,410,428
373.00	Street Lighting and Signal Systems	264,812,434	14,493,162	5.47%	-10%	276,800,515	21.6	4.84%	12,814,839
	Total Distribution Plant	**6,869,268,718**	**3,308,642,984**	**48.17%**		**4,992,701,903**	**31.3**	**2.32%**	**159,332,401**
	General Plant								
390.00	Structures and Improvements	156,446,136	31,155,047	19.91%	-5%	133,113,396	35.0	2.43%	3,803,240
391.00	Office Furniture and Equipment								
	Fully Accrued	10,200,215	10,200,215	100.00%	0%	0	0.0	0.00%	0
	Amortized	14,520,609	2,860,000	19.70%	0%	11,660,609	17.5	4.59%	666,321
	Total Account 391	*24,720,824*	*13,060,215*	*52.83%*		*11,660,609*	*17.5*	*2.70%*	*666,321*
391.10	Office Furniture and Equipment - EDP	61,586,228	20,800,000	33.77%	0%	40,786,228	5.3	12.50%	7,695,515
392.00	Transportation Equipment	69,975,818	34,325,441	49.05%	15%	25,154,004	5.6	6.42%	4,491,786
393.00	Stores Equipment	2,059,933	822,000	39.90%	0%	1,237,933	12.0	5.01%	103,161
394.00	Tools, Shop, and Garage Equipment	90,247,659	21,910,000	24.28%	0%	68,337,659	15.2	4.98%	4,495,899
395.00	Laboratory Equipment	6,739,789	3,908,000	57.98%	0%	2,831,789	6.3	6.67%	449,490
396.00	Power Operated Equipment	5,679,686	2,225,815	39.19%	0%	3,453,872	8.4	7.24%	411,175
397.00	Communication Equipment								
	Fully Accrued	59,435,956	59,435,956	100.00%	0%	0	0.0	0.00%	0
	Amortized	120,535,863	53,890,000	44.71%	0%	66,645,863	16.9	3.27%	3,943,542
	Total Account 397	*179,971,819*	*113,325,956*	*62.97%*		*66,645,863*	*16.9*	*2.19%*	*3,943,542*
398.00	Miscellaneous Equipment	23,040,258	15,615,000	67.77%	0%	7,425,258	6.5	4.96%	1,142,347
	Total General Plant	**620,468,150**	**257,147,474**	**41.44%**		**360,646,611**	**13.3**	**4.38%**	**27,202,476**
	Total Transmission, Distribution, and Genera	**10,045,309,708**	**4,327,794,170**	**43.08%**		**7,849,978,310**	**32.2**	**2.43%**	**243,644,758**
	Depreciable Land Rights								
310.00	Land Rights								
	Asheville Unit 1	919,202	1,049,268	114.15%	0%	(130,066)	0.0	0.00%	0
	Mayo Unit 1	3,577,118	3,213,884	89.85%	0%	363,233	10.5	0.97%	34,594
	Roxboro Unit 1	1,827,203	1,910,729	104.57%	0%	(83,526)	0.0	0.00%	0
	Roxboro Unit 3	3,037,934	3,151,250	103.73%	0%	(113,316)	0.0	0.00%	0
	Total Account 310	*9,361,457*	*9,325,132*	*99.61%*		*36,324*	*1.1*	*0.37%*	*34,594*
320.00	Land Rights								
	Harris Unit 1	49,809,293	33,296,139	66.85%	0%	16,513,154	27.5	1.21%	600,478
	Robinson Unit 2	315,920	316,714	100.25%	0%	(794)	0.0	0.00%	0
	Total Account 320	*50,125,213*	*33,612,853*	*67.06%*		*16,512,360*	*27.5*	*1.20%*	*600,478*
320.10	Rights of Way								
	Brunswick Unit 1	9,724	8,156	83.87%	0%	1,568	17.4	0.93%	90
	Brunswick Unit 2	51,363	49,976	97.30%	0%	1,388	15.8	0.17%	88
	Robinson Unit 2	6,141	6,141	100.00%	0%	0	0.0	0.00%	0
	Total Account 320.10	*67,228*	*64,272*	*95.60%*		*2,956*	*16.6*	*0.26%*	*178*
330.00	Land Rights								
	Walters	80,797	50,520	62.53%	0%	30,277	14.0	2.68%	2,163
	Total Account 330	*80,797*	*50,520*	*62.53%*		*30,277*	*14.0*	*2.68%*	*2,163*
330.10	Rights of Way								
	Blewett	9,598	6,297	65.61%	0%	3,301	16.9	2.04%	195
	Marshall	3,729	2,548	68.34%	0%	1,180	12.0	2.64%	98
	Tillery	19,764	13,269	67.14%	0%	6,495	24.9	1.32%	261
	Walters	33,333	20,634	61.90%	0%	12,699	14.3	2.66%	888

Duke Energy Progress
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	Total Account 330.1	*66,424*	*42,748*	*64.36%*		*23,676*	*16.4*	*2.17%*	*1,443*
340.00	Land Rights								
	H.F. Lee IC Turbines (Wayne County Units	2,048,655	1,037,253	50.63%	0%	1,011,402	20.6	2.40%	49,097
	Total Account 340	*2,048,655*	*1,037,253*	*50.63%*		*1,011,402*	*20.6*	*2.40%*	*49,097*
340.10	Rights of Way								
	H.F. Lee IC Turbines (Wayne County Units	2,532,367	1,106,468	43.69%	0%	1,425,899	21.0	2.68%	67,900
	Total Account 340.1	*2,532,367*	*1,106,468*	*43.69%*		*1,425,899*	*21.0*	*2.68%*	*67,900*
350.10	Rights of Way	176,749,824	68,578,311	38.80%	0%	108,171,513	53.0	1.15%	2,040,972
360.00	Land Rights	107,521	19,073	17.74%	0%	88,448	55.8	1.47%	1,585
360.10	Rights of Way	23,908,367	12,009,169	50.23%	0%	11,899,199	39.8	1.25%	298,975
389.10	Rights of Way	51,783	(670,230)	-1294.30%	0%	722,014	26.6	52.42%	27,143
	Total Depreciable Land Rights	**265,099,637**	**125,175,569**	**47.22%**		**139,924,068**	**44.8**	**1.18%**	**3,124,528**
	Reserve Adjustment for Amortization								
391.00	Office Furniture and Equipment		(17,130,482)			17,130,482			0
393.00	Stores Equipment		(762,086)			762,086			0
394.00	Tools, Shop, and Garage Equipment		(11,388,283)			11,388,283			0
395.00	Laboratory Equipment		398,322			(398,322)			0
397.00	Communication Equipment		(56,777,491)			56,777,491			0
398.00	Miscellaneous Equipment		(6,986,450)			6,986,450			0
	Total Reserve Adjustment for Amortization		**(92,646,470)**			**92,646,470**			**0**
	Total Depreciable Plant	**26,397,951,517**	**10,971,222,183**	**41.56%**		**17,954,787,866**	**20.7**	**3.28%**	**865,341,234**

Duke Energy Progress
Table 5: Current and Proposed Parameters
As of December 31, 2018

		Current				Company Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Steam Production Plant														
311.00	Structures and Improvements														
	Asheville Unit 1	12-2027	100	R2.5	-4%	12-2027	100	R2.5	9.0	-4%	12-2027	100	R2.5	9.0	-4%
	Asheville Unit 2	12-2027	100	R2.5	-4%	12-2027	100	R2.5	9.0	-4%	12-2027	100	R2.5	9.0	-4%
	Mayo Unit 1	06-2035	100	R2.5	-6%	06-2029	100	R2.5	10.4	-4%	06-2035	100	R2.5	16.3	-4%
	Roxboro Unit 1	06-2028	100	R2.5	-6%	06-2028	100	R2.5	9.5	-5%	06-2028	100	R2.5	9.5	-4%
	Roxboro Unit 2	06-2028	100	R2.5	-6%	06-2028	100	R2.5	9.5	-5%	06-2028	100	R2.5	9.5	-4%
	Roxboro Unit 3	06-2033	100	R2.5	-6%	06-2029	100	R2.5	10.5	-5%	06-2033	100	R2.5	14.3	-4%
	Roxboro Unit 4	06-2033	100	R2.5	-6%	06-2029	100	R2.5	10.4	-5%	06-2033	100	R2.5	14.4	-4%
	Roxboro Common	06-2033	100	R2.5	-6%	06-2029	100	R2.5	10.4	-5%	06-2033	100	R2.5	14.4	-4%
	Total Structures and Improvements														
312.00	Boiler Plant Equipment														
	Asheville Unit 1	12-2027	60	R1	-4%	12-2027	60	R1	8.8	-4%	12-2027	60	R1	8.8	-4%
	Asheville Unit 2	12-2027	60	R1	-4%	12-2027	60	R1	8.8	-4%	12-2027	60	R1	8.8	-4%
	Mayo Unit 1	06-2035	60	R1	-6%	06-2029	60	R1	10.1	-4%	06-2035	60	R1	15.6	-4%
	Roxboro Unit 1	06-2028	60	R1	-6%	06-2028	60	R1	9.2	-5%	06-2028	60	R1	9.2	-4%
	Roxboro Unit 2	06-2028	60	R1	-6%	06-2028	60	R1	9.2	-5%	06-2028	60	R1	9.2	-4%
	Roxboro Unit 3	06-2033	60	R1	-6%	06-2029	60	R1	10.1	-5%	06-2033	60	R1	13.8	-4%
	Roxboro Unit 4	06-2033	60	R1	-6%	06-2029	60	R1	10.2	-5%	06-2033	60	R1	13.8	-4%
	Roxboro Common	06-2033	60	R1	-6%	06-2029	60	R1	10.2	-5%	06-2033	60	R1	13.9	-4%
	Total Boiler Plant Equipment														
312.10	Boiler Plant Equipment - SCR Catalyst														
	Asheville Unit 1	12-2027	10	S2	0%	12-2027	10	S1	0.0	0%	12-2027	10	S1	0.0	0%
	Asheville Unit 2	12-2027	10	S2	0%	12-2027	10	S1	0.0	0%	12-2027	10	S1	0.0	0%
	Mayo Unit 1	06-2035	10	S2	0%	06-2029	10	S1	0.0	0%	06-2035	10	S1	3.9	0%
	Roxboro Unit 1	06-2028	10	S2	0%	06-2028	10	S1	0.0	0%	06-2028	10	S1	0.0	0%
	Roxboro Unit 2	06-2028	10	S2	0%	06-2028	10	S1	0.0	0%	06-2028	10	S1	0.0	0%
	Roxboro Unit 3	06-2033	10	S2	0%	06-2029	10	S1	6.3	0%	06-2033	10	S1	5.1	0%
	Roxboro Unit 4	06-2033	10	S2	0%	06-2029	10	S1	0.0	0%	06-2033	10	S1	3.3	0%
	Total Boiler Plant Equipment														
314.00	Turbogenerator Units														
	Asheville Unit 1	12-2027	60	S0	-4%	12-2027	60	S0	8.7	-4%	12-2027	60	S0	8.7	-4%
	Asheville Unit 2	12-2027	60	S0	-4%	12-2027	60	S0	8.9	-4%	12-2027	60	S0	8.9	-4%
	Mayo Unit 1	06-2035	60	S0	-6%	06-2029	60	S0	10.0	-4%	06-2035	60	S0	15.2	-4%
	Roxboro Unit 1	06-2028	60	S0	-6%	06-2028	60	S0	9.2	-5%	06-2028	60	S0	9.2	-4%
	Roxboro Unit 2	06-2028	60	S0	-6%	06-2028	60	S0	9.2	-5%	06-2028	60	S0	9.2	-4%
	Roxboro Unit 3	06-2033	60	S0	-6%	06-2029	60	S0	10.1	-5%	06-2033	60	S0	13.8	-4%
	Roxboro Unit 4	06-2033	60	S0	-6%	06-2029	60	S0	10.1	-5%	06-2033	60	S0	13.7	-4%
	Roxboro Common	06-2033	60	S0	-6%	06-2029	60	S0	10.0	-5%	06-2033	60	S0	13.5	-4%
	Total Turbogenerator Units														
315.00	Accessory Electric Equipment														
	Asheville Unit 1	12-2027	65	R1.5	-4%	12-2027	70	R1	8.8	-4%	12-2027	70	R1	8.8	-4%
	Asheville Unit 2	12-2027	65	R1.5	-4%	12-2027	70	R1	0.0	-4%	12-2027	70	R1	0.0	-4%
	Mayo Unit 1	06-2035	65	R1.5	-6%	06-2029	70	R1	10.2	-4%	06-2035	70	R1	15.7	-4%
	Roxboro Unit 1	06-2028	65	R1.5	-6%	06-2028	70	R1	9.3	-5%	06-2028	70	R1	9.3	-4%
	Roxboro Unit 2	06-2028	65	R1.5	-6%	06-2028	70	R1	9.3	-5%	06-2028	70	R1	9.3	-4%
	Roxboro Unit 3	06-2033	65	R1.5	-6%	06-2029	70	R1	10.2	-5%	06-2033	70	R1	13.9	-4%
	Roxboro Unit 4	06-2033	65	R1.5	-6%	06-2029	70	R1	10.2	-5%	06-2033	70	R1	13.9	-4%
	Roxboro Common	06-2033	65	R1.5	-6%	06-2029	70	R1	10.2	-5%	06-2033	70	R1	14.0	-4%
	Total Accessory Electric Equipment														
316.00	Miscellaneous Power Plant Equipment														
	Asheville Unit 1	12-2027	50	S0	-4%	12-2027	45	S0	8.7	-4%	12-2027	45	S0	8.7	-4%
	Asheville Unit 2	12-2027	50	S0	-4%	12-2027	45	S0	8.6	-4%	12-2027	45	S0	8.6	-4%
	Mayo Unit 1	06-2035	50	S0	-6%	06-2029	45	S0	9.9	-4%	06-2035	45	S0	14.9	-4%
	Roxboro Unit 1	06-2028	50	S0	-6%	06-2028	45	S0	9.1	-5%	06-2028	45	S0	9.1	-4%
	Roxboro Unit 2	06-2028	50	S0	-6%	06-2028	45	S0	9.1	-5%	06-2028	45	S0	9.1	-4%
	Roxboro Unit 3	06-2033	50	S0	-6%	06-2029	45	S0	9.9	-5%	06-2033	45	S0	13.3	-4%
	Roxboro Unit 4	06-2033	50	S0	-6%	06-2029	45	S0	9.7	-5%	06-2033	45	S0	13.0	-4%

Duke Energy Progress
Table 5: Current and Proposed Parameters
As of December 31, 2018

		Current				Company Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Roxboro Common	06-2033	50	S0	-6%	06-2029	45	S0	10.0	-5%	06-2033	45	S0	13.5	-4%
	Total Miscellaneous Power Plant Equipment														
	Total Steam Production Plant														
	Nuclear Production Plant														
321.00	Structures and Improvements														
	Brunswick Unit 1	09-2036	80	S1	-2%	09-2036	75	S1	17.3	-1%	09-2036	75	S1	17.3	-1%
	Brunswick Unit 2	12-2034	80	S1	-2%	12-2034	75	S1	15.5	-1%	12-2034	75	S1	15.5	-1%
	Harris Unit 1	10-2046	80	S1	-3%	10-2046	75	S1	25.8	-2%	10-2046	75	S1	25.8	-2%
	Harris Disallowance					10-2046			27.8		10-2046			27.8	
	Robinson Unit 2	07-2030	80	S1	-1%	07-2030	75	S1	11.4	-1%	07-2030	75	S1	11.4	-1%
	Total Structures and Improvements														
322.00	Reactor Plant Equipment														
	Brunswick Unit 1	09-2036	55	R1.5	-2%	09-2036	52	R2	16.5	-1%	09-2036	52	R2	16.5	-1%
	Brunswick Unit 2	12-2034	55	R1.5	-2%	12-2034	52	R2	15.0	-1%	12-2034	52	R2	15.0	-1%
	Harris Unit 1	10-2046	55	R1.5	-3%	10-2046	52	R2	23.3	-2%	10-2046	52	R2	23.3	-2%
	Harris Disallowance					10-2046			27.8		10-2046			27.8	
	Robinson Unit 2	07-2030	55	R1.5	-1%	07-2030	52	R2	11.2	-1%	07-2030	52	R2	11.2	-1%
	Total Reactor Plant Equipment														
323.00	Turbogenerator Units														
	Brunswick Unit 1	09-2036	50	S0	-2%	09-2036	40	S0	15.8	-1%	09-2036	40	S0	15.8	-1%
	Brunswick Unit 2	12-2034	50	S0	-2%	12-2034	40	S0	14.1	-1%	12-2034	40	S0	14.1	-1%
	Harris Unit 1	10-2046	50	S0	-3%	10-2046	40	S0	22.9	-2%	10-2046	40	S0	22.9	-2%
	Harris Disallowance					10-2046			27.8		10-2046			27.8	
	Robinson Unit 2	07-2030	50	S0	-1%	07-2030	40	S0	11.0	-1%	07-2030	40	S0	11.0	-1%
	Total Turbogenerator Units														
324.00	Accessory Electric Equipment														
	Brunswick Unit 1	09-2036	55	R2.5	-2%	09-2036	50	R2.5	16.8	-1%	09-2036	50	R2.5	16.8	-1%
	Brunswick Unit 2	12-2034	55	R2.5	-2%	12-2034	50	R2.5	15.3	-1%	12-2034	50	R2.5	15.3	-1%
	Harris Unit 1	10-2046	55	R2.5	-3%	10-2046	50	R2.5	23.9	-2%	10-2046	50	R2.5	23.9	-2%
	Harris Disallowance					10-2046			27.8		10-2046			27.8	
	Robinson Unit 2	07-2030	55	R2.5	-1%	07-2030	50	R2.5	11.4	-1%	07-2030	50	R2.5	11.4	-1%
	Total Accessory Electric Equipment														
325.00	Miscellaneous Power Plant Equipment														
	Brunswick Unit 1	09-2036	50	R1	-2%	09-2036	50	R1.5	16.6	-1%	09-2036	50	R1.5	16.6	-1%
	Brunswick Unit 2	12-2034	50	R1	-2%	12-2034	50	R1.5	15.0	-1%	12-2034	50	R1.5	15.0	-1%
	Harris Unit 1	10-2046	50	R1	-3%	10-2046	50	R1.5	24.1	-2%	10-2046	50	R1.5	24.1	-2%
	Harris Disallowance					10-2046			27.8		10-2046			27.8	
	Robinson Unit 2	07-2030	50	R1	-1%	07-2030	50	R1.5	11.2	-1%	07-2030	50	R1.5	11.2	-1%
	Total Miscellaneous Power Plant Equipment														
	Total Nuclear Production Plant														
	Hydraulic Production Plant														
331.00	Structures and Improvements														
	Blewett	06-2055	110	R2	-41%	06-2055	110	R2	35.1	-33%	06-2055	110	R2	35.1	-31%
	Marshall	06-2035	110	R2	-16%	06-2035	110	R2	16.2	-16%	06-2035	110	R2	16.2	-14%
	Tillery	06-2055	110	R2	-33%	06-2055	110	R2	35.1	-29%	06-2055	110	R2	35.1	-27%
	Walters	06-2034	110	R2	-6%	06-2034	110	R2	15.2	-6%	06-2034	110	R2	15.2	-6%
	Total Structures and Improvements														
332.00	Reservoirs, Dams, and Waterways														
	Blewett	06-2055	120	R3	-41%	06-2055	120	R3	34.6	-33%	06-2055	120	R3	34.6	-31%
	Marshall	06-2035	120	R3	-16%	06-2035	120	R3	16.4	-16%	06-2035	120	R3	16.4	-14%
	Tillery	06-2055	120	R3	-33%	06-2055	120	R3	34.8	-29%	06-2055	120	R3	34.8	-27%
	Walters	06-2034	120	R3	-6%	06-2034	120	R3	15.4	-6%	06-2034	120	R3	15.4	-6%
	Total Reservoirs, Dams, and Waterways														

Duke Energy Progress
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As of December 31, 2018

		Current				Company Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
333.00	Water Wheels, Turbines, and Generators														
	Blewett	06-2055	70	R1.5	-41%	06-2055	75	R1.5	32.8	-33%	06-2055	75	R1.5	32.8	-31%
	Marshall	06-2035	70	R1.5	-16%	06-2035	75	R1.5	15.7	-16%	06-2035	75	R1.5	15.7	-14%
	Tillery	06-2055	70	R1.5	-33%	06-2055	75	R1.5	32.4	-29%	06-2055	75	R1.5	32.4	-27%
	Walters	06-2034	70	R1.5	-6%	06-2034	75	R1.5	14.9	-6%	06-2034	75	R1.5	14.9	-6%
	Total Water Wheels, Turbines, and Generators														
334.00	Accessory Electric Equipment														
	Blewett	06-2055	60	S1	-41%	06-2055	55	R1	30.2	-33%	06-2055	55	R1	30.2	-31%
	Marshall	06-2035	60	S1	-16%	06-2035	55	R1	14.8	-16%	06-2035	55	R1	14.8	-14%
	Tillery	06-2055	60	S1	-33%	06-2055	55	R1	29.3	-29%	06-2055	55	R1	29.3	-27%
	Walters	06-2034	60	S1	-6%	06-2034	55	R1	14.8	-6%	06-2034	55	R1	14.8	-6%
	Total Accessory Electric Equipment														
335.00	Miscellaneous Power Plant Equipment														
	Blewett	06-2055	55	S0.5	-41%	06-2055	55	S0	30.0	-33%	06-2055	55	S0	30.0	-31%
	Marshall	06-2035	55	S0.5	-16%	06-2035	55	S0	15.2	-16%	06-2035	55	S0	15.2	-14%
	Tillery	06-2055	55	S0.5	-33%	06-2055	55	S0	29.8	-29%	06-2055	55	S0	29.8	-27%
	Walters	06-2034	55	S0.5	-6%	06-2034	55	S0	14.6	-6%	06-2034	55	S0	14.6	-6%
	Total Miscellaneous Power Plant Equipment														
336.00	Roads, Railroads, and Bridges														
	Marshall	06-2035	75	R3	-16%	06-2035	75	R3	15.9	-16%	06-2035	75	R3	15.9	-14%
	Walters	06-2034	75	R3	-6%	06-2034	75	R3	11.7	-6%	06-2034	75	R3	11.7	-6%
	Total Roads, Railroads, and Bridges														
	Total Hydraulic Production Plant														
	Other Production Plant														
341.00	Structures and Improvements														
	Asheville IC Turbine	06-2039	50	S2	-3%	06-2039	50	S1	18.1	-3%	06-2039	50	S1	18.1	-3%
	Blewett IC Turbines	06-2024	50	S2	-7%	06-2024	50	S1	5.5	-7%	06-2024	50	S1	5.5	-6%
	Darlington IC Turbine Units 1-11	06-2020	50	S2	-6%	06-2020	50	S1	0.0	-7%	06-2020	50	S1	0.0	-6%
	Darlington IC Turbine Units 12 & 13	06-2037	50	S2	-6%	06-2037	50	S1	17.1	-7%	06-2037	50	S1	17.1	-6%
	H.F. Lee IC Turbines (Wayne County Units 1(	06-2040	50	S2	-4%	06-2040	50	S1	19.1	-4%	06-2040	50	S1	19.1	-4%
	H.F. Lee IC Turbines (Wayne County Units 14	06-2049	50	S2	-4%	06-2049	50	S1	27.0	-4%	06-2049	50	S1	27.0	-4%
	Smith IC Turbines (Richmond County)	06-2041	50	S2	-2%	06-2041	50	S1	20.5	-2%	06-2041	50	S1	20.5	-2%
	Sutton Blackstart		50	S2	-20%	06-2057	50	S1	34.6	-9%	06-2057	50	S1	34.6	-9%
	Weatherspoon IC Turbines	06-2024	50	S2	-20%	06-2024	50	S1	5.2	-21%	06-2024	50	S1	5.2	-19%
	Smith CC Power Block 4 (Richmond County)	06-2042	50	S2	-3%	06-2042	50	S1	20.6	-4%	06-2042	50	S1	20.6	-3%
	Smith CC Power Block 5 (Richmond County)	06-2051	50	S2	-7%	06-2051	50	S1	28.7	-8%	06-2051	50	S1	28.7	-7%
	Sutton CC	06-2053	50	S2	-2%	06-2053	50	S1	30.7	-3%	06-2053	50	S1	30.7	-2%
	H.F. Lee CC (Wayne County)	06-2052	50	S2	-5%	06-2052	50	S1	27.6	-6%	06-2052	50	S1	27.6	-5%
	Total Structures and Improvements														
341.20	Structures and Improvements - Solar														
	Camp Lejune	06-2040	25	S2.5	-8%	06-2040	30	S2.5	20.6	-9%	06-2040	30	S2.5	20.6	-8%
	Fayetteville	06-2040	25	S2.5	-10%	06-2040	30	S2.5	20.3	-11%	06-2040	30	S2.5	20.3	-9%
	Elm City	06-2041	25	S2.5	-15%	06-2041	30	S2.5	21.0	-15%	06-2041	30	S2.5	21.0	-13%
	Total Structures and Improvements - Solar														
342.00	Fuel Holders, Producers, and Accessories														
	Asheville IC Turbine	06-2039	50	R2.5	-3%	06-2039	45	R2	18.7	-3%	06-2039	45	R2	18.7	-3%
	Blewett IC Turbines	06-2024	50	R2.5	-7%	06-2024	45	R2	5.4	-7%	06-2024	45	R2	5.4	-6%
	Darlington IC Turbine Units 1-11	06-2020	50	R2.5	-6%	06-2020	45	R2	0.0	-7%	06-2020	45	R2	0.0	-6%
	Darlington IC Turbine Units 12 & 13	06-2037	50	R2.5	-6%	06-2037	45	R2	17.3	-7%	06-2037	45	R2	17.3	-6%
	H.F. Lee IC Turbines (Wayne County Units 1(	06-2040	50	R2.5	-4%	06-2040	45	R2	19.1	-4%	06-2040	45	R2	19.1	-4%
	H.F. Lee IC Turbines (Wayne County Units 14	06-2049	50	R2.5	-4%	06-2049	45	R2	26.7	-4%	06-2049	45	R2	26.7	-4%
	Smith IC Turbines (Richmond County)	06-2041	50	R2.5	-2%	06-2041	45	R2	19.8	-2%	06-2041	45	R2	19.8	-2%
	Sutton Blackstart		50	R2.5	0%	06-2057	45	R2	34.0	-9%	06-2057	45	R2	34.0	-9%
	Weatherspoon IC Turbines	06-2024	50	R2.5	-20%	06-2024	45	R2	5.4	-21%	06-2024	45	R2	5.4	-19%
	Smith CC Power Block 4 (Richmond County)	06-2042	50	R2.5	-3%	06-2042	45	R2	20.8	-4%	06-2042	45	R2	20.8	-3%

Duke Energy Progress
Table 5: Current and Proposed Parameters
As of December 31, 2018

		Current				Company Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Smith CC Power Block 5 (Richmond County)	06-2051	50	R2.5	-7%	06-2051	45	R2	28.5	-8%	06-2051	45	R2	28.5	-7%
	Sutton CC	06-2053	50	R2.5	-2%	06-2053	45	R2	30.6	-3%	06-2053	45	R2	30.6	-2%
	H.F. Lee CC (Wayne County)	06-2052	50	R2.5	-5%	06-2052	45	R2	29.4	-6%	06-2052	45	R2	29.4	-5%
	Total Fuel Holders, Producers, and Accessories														
343.00	Prime Movers														
	Asheville IC Turbine	06-2039	35	S0	-3%	06-2039	30	R0.5	16.9	-3%	06-2039	30	R0.5	16.9	-3%
	Blewett IC Turbines	06-2024	35	S0	-7%	06-2024	30	R0.5	4.9	-7%	06-2024	30	R0.5	4.9	-6%
	Darlington IC Turbine Units 1-11	06-2020	35	S0	-6%	06-2020	30	R0.5	1.5	-7%	06-2020	30	R0.5	1.5	-6%
	Darlington IC Turbine Units 12 & 13	06-2037	35	S0	-6%	06-2037	30	R0.5	14.7	-7%	06-2037	30	R0.5	14.7	-6%
	H.F. Lee IC Turbines (Wayne County Units 1(	06-2040	35	S0	-4%	06-2040	30	R0.5	16.6	-4%	06-2040	30	R0.5	16.6	-4%
	H.F. Lee IC Turbines (Wayne County Units 1⁄	06-2049	35	S0	-4%	06-2049	30	R0.5	21.3	-4%	06-2049	30	R0.5	21.3	-4%
	Smith IC Turbines (Richmond County)	06-2041	35	S0	-2%	06-2041	30	R0.5	17.7	-2%	06-2041	30	R0.5	17.7	-2%
	Sutton Blackstart					06-2057	30	R0.5	26.3	-9%	06-2057	30	R0.5	26.3	-9%
	Weatherspoon IC Turbines	06-2024	35	S0	-20%	06-2024	30	R0.5	5.1	-21%	06-2024	30	R0.5	5.1	-19%
	Smith CC Power Block 4 (Richmond County)	06-2042	35	S0	-3%	06-2042	30	R0.5	17.5	-4%	06-2042	30	R0.5	17.5	-3%
	Smith CC Power Block 5 (Richmond County)	06-2051	35	S0	-7%	06-2051	30	R0.5	22.4	-8%	06-2051	30	R0.5	22.4	-7%
	Sutton CC	06-2053	35	S0	-2%	06-2053	30	R0.5	23.8	-3%	06-2053	30	R0.5	23.8	-2%
	H.F. Lee CC (Wayne County)	06-2052	35	S0	-5%	06-2052	30	R0.5	23.1	-6%	06-2052	30	R0.5	23.1	-5%
	Total Prime Movers														
343.10	Prime Movers - Rotable Parts														
	Smith CC Power Block 4 (Richmond County)	06-2042	5	L0.5	40%	06-2042	6	L0.5	4.2	40%	06-2042	6	L0.5	4.2	40%
	Smith CC Power Block 5 (Richmond County)	06-2051	5	L0.5	40%	06-2051	6	L0.5	3.2	40%	06-2051	6	L0.5	3.2	40%
	Sutton CC	06-2053	5	L0.5	40%	06-2053	6	L0.5	3.4	40%	06-2053	6	L0.5	3.4	40%
	H.F. Lee CC (Wayne County)	06-2052	5	L0.5	40%	06-2052	6	L0.5	3.8	40%	06-2052	6	L0.5	3.8	40%
	Total Prime Movers - Rotable Parts														
344.00	Generators														
	Asheville IC Turbine	06-2039	55	R2	-3%	06-2039	50	R2	18.7	-3%	06-2039	50	R2	18.7	-3%
	Blewett IC Turbines	06-2024	55	R2	-7%	06-2024	50	R2	0.0	-7%	06-2024	50	R2	0.0	-6%
	Darlington IC Turbine Units 1-11	06-2020	55	R2	-6%	06-2020	50	R2	1.5	-7%	06-2020	50	R2	1.5	-6%
	Darlington IC Turbine Units 12 & 13	06-2037	55	R2	-6%	06-2037	50	R2	17.2	-7%	06-2037	50	R2	17.2	-6%
	H.F. Lee IC Turbines (Wayne County Units 1(	06-2040	55	R2	-4%	06-2040	50	R2	19.5	-4%	06-2040	50	R2	19.5	-4%
	H.F. Lee IC Turbines (Wayne County Units 1⁄	06-2049	55	R2	-4%	06-2049	50	R2	27.5	-4%	06-2049	50	R2	27.5	-4%
	Smith IC Turbines (Richmond County)	06-2041	55	R2	-2%	06-2041	50	R2	20.5	-2%	06-2041	50	R2	20.5	-2%
	Sutton Blackstart					06-2057	50	R2	34.8	-9%	06-2057	50	R2	34.8	-9%
	Weatherspoon IC Turbines	06-2024	55	R2	-20%	06-2024	50	R2	0.0	-21%	06-2024	50	R2	0.0	-19%
	Smith CC Power Block 4 (Richmond County)	06-2042	55	R2	-3%	06-2042	50	R2	0.0	-4%	06-2042	50	R2	0.0	-3%
	Smith CC Power Block 5 (Richmond County)	06-2051	55	R2	-7%	06-2051	50	R2	29.3	-8%	06-2051	50	R2	29.3	-7%
	Sutton CC	06-2053	55	R2	-2%	06-2053	50	R2	31.1	-3%	06-2053	50	R2	31.1	-2%
	H.F. Lee CC (Wayne County)	06-2052	55	R2	-5%	06-2052	50	R2	30.2	-6%	06-2052	50	R2	30.2	-5%
	Total Generators														
344.20	Generators - Solar														
	Camp Lejune	06-2040	25	S2.5	-8%	06-2040	25	S2.5	18.8	-9%	06-2040	25	S2.5	18.8	-8%
	Fayetteville	06-2040	25	S2.5	-10%	06-2040	25	S2.5	18.7	-11%	06-2040	25	S2.5	18.7	-9%
	Elm City	06-2041	25	S2.5	-15%	06-2041	25	S2.5	19.7	-15%	06-2041	25	S2.5	19.7	-13%
	Warsaw	06-2040	25	S2.5	-11%	06-2040	25	S2.5	18.7	-12%	06-2040	25	S2.5	18.7	-10%
	Total Generators - Solar														
345.00	Accessory Electric Equipment														
	Asheville IC Turbine	06-2039	50	R1.5	-3%	06-2039	50	R1.5	19.0	-3%	06-2039	50	R1.5	19.0	-3%
	Blewett IC Turbines	06-2024	50	R1.5	-7%	06-2024	50	R1.5	5.4	-7%	06-2024	50	R1.5	5.4	-6%
	Darlington IC Turbine Units 1-11	06-2020	50	R1.5	-6%	06-2020	50	R1.5	1.5	-7%	06-2020	50	R1.5	1.5	-6%
	Darlington IC Turbine Units 12 & 13	06-2037	50	R1.5	-6%	06-2037	50	R1.5	17.0	-7%	06-2037	50	R1.5	17.0	-6%
	H.F. Lee IC Turbines (Wayne County Units 1(	06-2040	50	R1.5	-4%	06-2040	50	R1.5	19.4	-4%	06-2040	50	R1.5	19.4	-4%
	H.F. Lee IC Turbines (Wayne County Units 1⁄	06-2049	50	R1.5	-4%	06-2049	50	R1.5	27.0	-4%	06-2049	50	R1.5	27.0	-4%
	Smith IC Turbines (Richmond County)	06-2041	50	R1.5	-2%	06-2041	50	R1.5	20.4	-2%	06-2041	50	R1.5	20.4	-2%
	Sutton Blackstart					06-2057	50	R1.5	33.9	-9%	06-2057	50	R1.5	33.9	-9%
	Weatherspoon IC Turbines	06-2024	50	R1.5	-20%	06-2024	50	R1.5	5.4	-21%	06-2024	50	R1.5	5.4	-19%
	Smith CC Power Block 4 (Richmond County)	06-2042	50	R1.5	-3%	06-2042	50	R1.5	21.3	-4%	06-2042	50	R1.5	21.3	-3%
	Smith CC Power Block 5 (Richmond County)	06-2051	50	R1.5	-7%	06-2051	50	R1.5	28.7	-8%	06-2051	50	R1.5	28.7	-7%
	Sutton CC	06-2053	50	R1.5	-2%	06-2053	50	R1.5	30.5	-3%	06-2053	50	R1.5	30.5	-2%

Duke Energy Progress
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As of December 31, 2018

		Current				Company Proposed					Public Staff Proposed				
Account	Description	AYFR	Proj Life	Iowa Curve Shape	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage	AYFR	Proj Life	Iowa Curve Shape	Avg Rem Life	Future Net Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	H.F. Lee CC (Wayne County)	06-2052	50	R1.5	-5%	06-2052	50	R1.5	29.6	-6%	06-2052	50	R1.5	29.6	-5%
	Total Accessory Electric Equipment														
345.20	Accessory Electric Equipment - Solar														
	Camp Lejune	06-2040	25	S2.5	-8%	06-2040	25	S2.5	18.8	-9%	06-2040	25	S2.5	18.8	-8%
	Fayetteville	06-2040	25	S2.5	-10%	06-2040	25	S2.5	18.7	-11%	06-2040	25	S2.5	18.7	-9%
	Elm City	06-2041	25	S2.5	-15%	06-2041	25	S2.5	19.6	-15%	06-2041	25	S2.5	19.6	-13%
	Warsaw	06-2040	25	S2.5	-11%	06-2040	25	S2.5	18.7	-12%	06-2040	25	S2.5	18.7	-10%
	Total Accessory Electric Equipment - Solar														
346.00	Miscellaneous Power Plant Equipment														
	Asheville IC Turbine	06-2039	40	S1.5	-3%	06-2039	30	S1	15.8	-3%	06-2039	30	S1	15.8	-3%
	Blewett IC Turbines	06-2024	40	S1.5	-7%	06-2024	30	S1	5.2	-7%	06-2024	30	S1	5.2	-6%
	Darlington IC Turbine Units 1-11	06-2020	40	S1.5	-6%	06-2020	30	S1	1.5	-7%	06-2020	30	S1	1.5	-6%
	Darlington IC Turbine Units 12 & 13	06-2037	40	S1.5	-6%	06-2037	30	S1	16.4	-7%	06-2037	30	S1	16.4	-6%
	H.F. Lee IC Turbines (Wayne County Units 1(	06-2040	40	S1.5	-4%	06-2040	30	S1	15.4	-4%	06-2040	30	S1	15.4	-4%
	H.F. Lee IC Turbines (Wayne County Units 1	06-2049	40	S1.5	-4%	06-2049	30	S1	20.0	-4%	06-2049	30	S1	20.0	-4%
	Smith IC Turbines (Richmond County)	06-2041	40	S1.5	-2%	06-2041	30	S1	17.0	-2%	06-2041	30	S1	17.0	-2%
	Sutton Blackstart					06-2057	30	S1	27.2	-9%	06-2057	30	S1	27.2	-9%
	Weatherspoon IC Turbines	06-2024	40	S1.5	-20%	06-2024	30	S1	5.3	-21%	06-2024	30	S1	5.3	-19%
	Smith CC Power Block 4 (Richmond County)	06-2042	40	S1.5	-3%	06-2042	30	S1	20.8	-4%	06-2042	30	S1	20.8	-3%
	Smith CC Power Block 5 (Richmond County)	06-2051	40	S1.5	-7%	06-2051	30	S1	21.6	-8%	06-2051	30	S1	21.6	-7%
	Sutton CC	06-2053	40	S1.5	-2%	06-2053	30	S1	23.8	-3%	06-2053	30	S1	23.8	-2%
	H.F. Lee CC (Wayne County)	06-2052	40	S1.5	-5%	06-2052	30	S1	22.8	-6%	06-2052	30	S1	22.8	-5%
	Total Miscellaneous Power Plant Equipment														
346.20	Miscellaneous Power Plant Equipment - Solar														
	Elm City	06-2041	25	S2.5	-15%	06-2041	30	S2.5	21.0	-15%	06-2041	30	S2.5	21.0	-13%
	Warsaw	06-2040	25	S2.5	-11%	06-2040	30	S2.5	20.5	-12%	06-2040	30	S2.5	20.5	-10%
	Total Miscellaneous Power Plant Equipment - Solar														
	Total Other Production Plant														
	Total Production Plant														
	Transmission Plant														
352.00	Structures and Improvements		60	R3	-10%		60	R3	42.2	-10%		60	R3	42.2	-10%
353.00	Station Equipment		60	R1	-15%		55	R1.5	42.2	-15%		55	R1.5	42.2	-15%
354.00	Towers and Fixtures		70	R4	-20%		75	R4	51.8	-20%		75	R4	51.8	-20%
355.00	Poles and Fixtures		48	R1.5	-30%		49	R1.5	40.9	-40%		49	R1.5	40.9	-40%
356.00	Overhead Conductors and Devices		70	R2	-30%		65	R2.5	51.3	-40%		65	R2.5	51.3	-40%
357.00	Underground Conduit		70	R3	-30%		60	R4	58.8	0%		60	R4	58.8	0%
358.00	Underground Conductors and Devices		45	S2.5	0%		45	S2.5	39.5	0%		45	S2.5	39.5	0%
359.00	Roads and Trails		75	R3	0%		75	R3	57.4	0%		75	R3	57.4	0%
	Total Transmission Plant														
	Distribution Plant														
361.00	Structures and Improvements		60	R2	-15%		60	R2	48.5	-15%		60	R2	48.5	-15%
362.00	Station Equipment		46	R1	-15%		48	R1	38.2	-15%		48	R1	38.2	-15%
364.00	Poles, Towers, and Fixtures		45	R2.5	-100%		45	R2.5	32.6	-100%		45	R2.5	32.6	-75%
365.00	Overhead Conductors and Devices		44	R1.5	-30%		45	R1	38.2	-30%		45	R1	38.2	-30%
366.00	Underground Conduit		45	S2.5	-10%		46	S2.5	33.2	-15%		46	S2.5	33.2	-10%
367.00	Underground Conductors and Devices		40	S2	-5%		42	S2	30.9	-5%		42	S2	30.9	-5%
368.00	Line Transformers		39	R2	-5%		40	R2	29.1	-5%		40	R2	29.1	-5%
369.00	Services		42	R3	-10%		55	R3	41.2	-20%		55	R3	41.2	-15%
370.00	Metering Equipment		30	R4	-15%		28	R4	26.9	-10%		28	R4	26.9	-10%
370.01	Meters		30	R4	-5%		28	R4	9.7	-5%		28	R4	9.7	-5%
370.02	Meters - Utility of the Future		17	S2.5	0%		15	S2.5	14.5	0%		17	S2.5	16.5	0%
371.00	Installations on Customers' Premises		25	L1.5	-10%		26	S0.5	22.1	-10%		26	S0.5	22.1	-10%
373.00	Street Lighting and Signal Systems		30	R1	-10%		25	R1	21.6	-10%		25	R1	21.6	-10%

Duke Energy Progress
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	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
	Total Distribution Plant														
	General Plant														
390.00	Structures and Improvements		45	R1.5	-5%		45	R1.5	35.0	-5%		45	R1.5	35.0	-5%
391.00	Office Furniture and Equipment														
	Fully Accrued		20	SQ	0%		15	SQ	0.0	0%		20	SQ	0.0	0%
	Amortized		20	SQ	0%		15	SQ	12.0	0%		20	SQ	17.5	0%
	Total Account 391														
391.10	Office Furniture and Equipment - EDP		8	SQ	0%		8	SQ	5.3	0%		8	SQ	5.3	0%
392.00	Transportation Equipment		11	L2	10%		11	L2	5.6	15%		11	L2	5.6	15%
393.00	Stores Equipment		20	SQ	0%		20	SQ	12.0	0%		20	SQ	12.0	0%
394.00	Tools, Shop, and Garage Equipment		20	SQ	0%		20	SQ	15.2	0%		20	SQ	15.2	0%
395.00	Laboratory Equipment		15	SQ	0%		15	SQ	6.3	0%		15	SQ	6.3	0%
396.00	Power Operated Equipment		12	S6	0%		12	S6	8.4	0%		12	S6	8.4	0%
397.00	Communication Equipment														
	Fully Accrued		20	SQ	0%		10	SQ	0.0	0%		20	SQ	0.0	0%
	Amortized		20	SQ	0%		10	SQ	5.5	0%		20	SQ	16.9	0%
	Total Account 397														
398.00	Miscellaneous Equipment		20	SQ	0%		20	SQ	6.5	0%		20	SQ	6.5	0%
	Total General Plant														
	Total Transmission, Distribution, and General Plant														
	Depreciable Land Rights														
310.00	Land Rights														
	Asheville Unit 1	12-2027	100	R4	0%	12-2027	100	R4	0.0	0%	12-2027	100	R4	0.0	0%
	Mayo Unit 1	06-2035	100	R4	0%	06-2029	100	R4	10.5	0%	06-2029	100	R4	10.5	0%
	Roxboro Unit 1	06-2028	100	R4	0%	06-2028	100	R4	0.0	0%	06-2028	100	R4	0.0	0%
	Roxboro Unit 3	06-2033	100	R4	0%	06-2029	100	R4	0.0	0%	06-2029	100	R4	0.0	0%
	Total Account 310														
320.00	Land Rights														
	Harris Unit 1	10-2046	100	R4	0%	10-2046	100	R4	27.5	0%	10-2046	100	R4	27.5	0%
	Robinson Unit 2	07-2030	100	R4	0%	07-2030	100	R4	0.0	0%	07-2030	100	R4	0.0	0%
	Total Account 320														
320.10	Rights of Way														
	Brunswick Unit 1	09-2036	100	R4	0%	09-2036	100	R4	17.4	0%	09-2036	100	R4	17.4	0%
	Brunswick Unit 2	12-2034	100	R4	0%	12-2034	100	R4	15.8	0%	12-2034	100	R4	15.8	0%
	Robinson Unit 2	07-2030	100	R4	0%	07-2030	100	R4	0.0	0%	07-2030	100	R4	0.0	0%
	Total Account 320.10														
330.00	Land Rights														
	Walters	06-2034	110	R4	0%	06-2034	110	R4	14.0	0%	06-2034	110	R4	14.0	0%
	Total Account 330														
330.10	Rights of Way														
	Blewett	06-2055	110	R4	0%	06-2055	110	R4	16.9	0%	06-2055	110	R4	16.9	0%
	Marshall	06-2035	110	R4	0%	06-2035	110	R4	12.0	0%	06-2035	110	R4	12.0	0%
	Tillery	06-2055	110	R4	0%	06-2055	110	R4	24.9	0%	06-2055	110	R4	24.9	0%
	Walters	06-2034	110	R4	0%	06-2034	110	R4	14.3	0%	06-2034	110	R4	14.3	0%
	Total Account 330.1														
340.00	Land Rights														
	H.F. Lee IC Turbines (Wayne County Units 1(	06-2040	60	R4	0%	06-2040	60	R4	20.6	0%	06-2040	60	R4	20.6	0%
	Total Account 340														

Duke Energy Progress
Table 5: Current and Proposed Parameters
As of December 31, 2018

		Current				Company Proposed					Public Staff Proposed				
				Iowa	Future			Iowa	Avg	Future			Iowa	Avg	Future
			Proj	Curve	Net		Proj	Curve	Rem	Net		Proj	Curve	Rem	Net
Account	Description	AYFR	Life	Shape	Salvage	AYFR	Life	Shape	Life	Salvage	AYFR	Life	Shape	Life	Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
340.10	Rights of Way														
	H.F. Lee IC Turbines (Wayne County Units 1(	06-2040	60	R4	0%	06-2040	60	R4	21.0	0%	06-2040	60	R4	21.0	0%
	Total Account 340.1														
350.10	Rights of Way		75	R3	0%		75	R3	53.0	0%		75	R3	53.0	0%
360.00	Land Rights		65	R3	0%		65	R3	55.8	0%		65	R3	55.8	0%
360.10	Rights of Way		65	R3	0%		65	R3	39.8	0%		65	R3	39.8	0%
389.10	Rights of Way		60	R3	0%		60	R3	26.6	0%		60	R3	26.6	0%
	Total Depreciable Land Rights														

I/A

Duke Energy Progress
Table 6: Calculation of Weighted Net Salvage Percent for Generation Plant
As of December 31, 2018

	Total	Terminal Retirements				Interim Retirements				Total		Estimated
	Future	Retirements	Net Salvage	Percent of	Net Salvage	Retirements	Net Salvage	Percent of	Net Salvage	Net Salvage	Total	Net Salvage
Location	Retirements	($)	($)	Total Retire	(%)	($)	($)	Total Retire	(%)	($)	Retirements	(%)
	(1)	(2)	(3)	(4)=(2)/(11)	(5)=(3)/(2)	(6)	(7)=(6)x(9)	(8)=(6)/(11)	(9)	(10)=(3)+(7)	(11)=(2)+(6)	(12)=(10)/(11)
Steam Production												
Asheville Coal (2 units)	(456,808,920)	(454,176,455)	16,635,596	99.42%	-4%	(2,632,465)	394,870	0.58%	-15%	17,030,466	(456,808,920)	-4%
Mayo Coal (2 boilers, 1 ST)	(1,192,496,167)	(1,108,674,592)	36,945,736	92.97%	-3%	(83,821,574)	12,573,236	7.03%	-15%	49,518,972	(1,192,496,167)	-4%
Roxboro Coal (4 units)	(2,288,874,446)	(2,142,600,644)	76,535,327	93.61%	-4%	(146,273,802)	21,941,070	6.39%	-15%	98,476,397	(2,288,874,446)	-4%
Total Steam Production	**(3,938,179,533)**	**(3,705,451,692)**	**130,116,659**	**94.09%**	**-4%**	**(232,727,841)**	**34,909,176**	**5.91%**	**-15%**	**165,025,835**	**(3,938,179,533)**	**-4%**
Nuclear Production Plant												
Brunswick	(3,078,206,856)	(2,545,638,041)		82.70%	0%	(532,568,815)	37,279,817	17.30%	-7%	37,279,817	(3,078,206,856)	-1%
Harris	(4,675,251,918)	(3,147,467,188)		67.32%	0%	(1,527,784,729)	106,944,931	32.68%	-7%	106,944,931	(4,675,251,918)	-2%
Robinson	(1,638,796,682)	(1,503,271,909)		91.73%	0%	(135,524,773)	9,486,734	8.27%	-7%	9,486,734	(1,638,796,682)	-1%
Total Nuclear Production	**(9,392,255,456)**	**(7,196,377,139)**	**0**	**76.62%**	**0%**	**(2,195,878,317)**	**153,711,482**	**23.38%**	**-7%**	**153,711,482**	**(9,392,255,456)**	**-2%**
Hydro Production Plant												
Blewett (6 units)	(37,702,202)	(30,076,674)	10,127,982	79.77%	-34%	(7,625,528)	1,372,595	20.23%	-18%	11,500,577	(37,702,202)	-31%
Marshall (2 units)	(13,028,861)	(11,935,721)	1,690,518	91.61%	-14%	(1,093,140)	196,765	8.39%	-18%	1,887,283	(13,028,861)	-14%
Tillery (4 units)	(32,653,770)	(25,207,175)	7,377,819	77.20%	-29%	(7,446,595)	1,340,387	22.80%	-18%	8,718,206	(32,653,770)	-27%
Walters (3 units)	(57,479,826)	(54,025,151)	2,636,482	93.99%	-5%	(3,454,675)	621,842	6.01%	-18%	3,258,324	(57,479,826)	-6%
Total Hydro Production	**(140,864,659)**	**(121,244,720)**	**21,832,801**	**86.07%**	**-18%**	**(19,619,939)**	**3,531,589**	**13.93%**	**-18%**	**25,364,390**	**(140,864,659)**	**-18%**
Other Production Plant												
Simple Cycle/Cumbustion Turbines												
Asheville CT (2 CTs)	(113,437,289)	(79,612,990)	1,535,138	70.18%	-2%	(33,824,299)	1,352,972	29.82%	-4%	2,888,110	(113,437,289)	-3%
Blewett CT (4 CTs)	(13,460,860)	(10,801,714)	765,398	80.25%	-7%	(2,659,147)	106,366	19.75%	-4%	871,764	(13,460,860)	-6%
Darlington (13 CTs)	(129,816,320)	(103,132,000)	6,970,115	79.44%	-7%	(26,684,320)	1,067,373	20.56%	-4%	8,037,488	(129,816,320)	-6%
H.F. Lee (Wayne County, 5 CTs)	(270,493,150)	(151,276,320)	6,342,520	55.93%	-4%	(119,216,830)	4,768,673	44.07%	-4%	11,111,193	(270,493,150)	-4%
Smith CT (5 CTs)	(332,213,213)	(211,611,488)	2,348,697	63.70%	-1%	(120,601,725)	4,824,069	36.30%	-4%	7,172,766	(332,213,213)	-2%
Sutton Blackstart	(100,187,704)	(44,240,006)	6,286,979	44.16%	-14%	(55,947,698)	2,237,908	55.84%	-4%	8,524,887	(100,187,704)	-9%
Weatherspoon (4 CTs)	(23,678,965)	(18,006,324)	4,196,930	76.04%	-23%	(5,672,641)	226,906	23.96%	-4%	4,423,836	(23,678,965)	-19%
Combined Cycle												
Smith CC (PB 4-2x1)	(242,493,573)	(151,237,177)	4,655,389	62.37%	-3%	(91,256,396)	3,650,256	37.63%	-4%	8,305,645	(242,493,573)	-3%
Smith CC (PB 5-2x1)	(390,116,278)	(187,894,437)	20,275,784	48.16%	-11%	(202,221,841)	8,088,874	51.84%	-4%	28,364,658	(390,116,278)	-7%
Sutton (2x1)	(510,235,598)	(227,845,835)	1,362,220	44.66%	-1%	(282,389,763)	11,295,591	55.34%	-4%	12,657,811	(510,235,598)	-2%
H.F. Lee (3x1)	(638,084,307)	(283,676,907)	20,228,969	44.46%	-7%	(354,407,401)	14,176,296	55.54%	-4%	34,405,265	(638,084,307)	-5%
Total Other Production	**(2,764,217,258)**	**(1,469,335,198)**	**74,968,139**	**53.16%**	**-5%**	**(1,294,882,060)**	**51,795,282**	**46.84%**	**-4%**	**126,763,421**	**(2,764,217,258)**	**-5%**
Solar Production												
Camp Lejeune	(18,743,440)	(10,059,469)	1,411,689	53.67%	-14%	(8,683,971)	0	46.33%	0%	1,411,689	(18,743,440)	-8%
Fayetteville	(33,006,453)	(17,642,536)	3,116,044	53.45%	-18%	(15,363,917)	0	46.55%	0%	3,116,044	(33,006,453)	-9%
Elm City	(52,011,085)	(27,697,501)	6,911,980	53.25%	-25%	(24,313,584)	0	46.75%	0%	6,911,980	(52,011,085)	-13%
Warsaw	(88,459,893)	(47,311,027)	9,027,920	53.48%	-19%	(41,148,865)	0	46.52%	0%	9,027,920	(88,459,893)	-10%
Total Solar Production	**(192,220,870)**	**(102,710,533)**	**20,467,633**	**53.43%**	**-20%**	**(89,510,337)**	**0**	**46.57%**	**0%**	**20,467,633**	**(192,220,870)**	**-11%**

Source:
Spanos Exhibit 1
DEP Response to PS DR 1-8

I/A

Duke Energy Progress
Table 7: Staff Calculation of Terminal Net Salvage Percent
As of December 31, 2018

Plant	Estimated Decommissioning Cost	Estimated Scrap Value	5% Estimated Project Indirects	10% Contigency	Estimated Decommissioning Cost (Current Year $)	2018 Current Dollar Year	Escalation Year	Adjusted Escalated Decommissioning Cost (Rate Year $)
	CONFIDENTIAL							
(1)	B	C	D	E	F	G	H	I=Fx(1+2.5%)^[H-G]
Steam Production								
Asheville Coal (2 units)	[redacted]	[redacted]	[redacted]	[redacted]	15,834,000	2018	2020	16,635,596
Mayo Coal (2 boilers, 1 ST)	[redacted]	[redacted]	[redacted]	[redacted]	28,158,000	2018	2029	36,945,736
Roxboro Coal (4 units)	[redacted]	[redacted]	[redacted]	[redacted]	58,331,000	2018	2029	76,535,327
Total Steam Production	[redacted]	[redacted]	[redacted]	[redacted]	**102,323,000**			**130,116,659**
Hydro Production Plant								
Blewett (6 units)	[redacted]	[redacted]	[redacted]	[redacted]	4,062,000	2018	2055	10,127,982
Marshall (2 units)	[redacted]	[redacted]	[redacted]	[redacted]	1,111,000	2018	2035	1,690,518
Tillery (4 units)	[redacted]	[redacted]	[redacted]	[redacted]	2,959,000	2018	2055	7,377,819
Walters (3 units)	[redacted]	[redacted]	[redacted]	[redacted]	1,776,000	2018	2034	2,636,482
Total Hydro Production	[redacted]	[redacted]	[redacted]	[redacted]	**9,908,000**			**21,832,801**
Other Production Plant								
Simple Cycle/Cumbustion Turbines								
Asheville CT (2 CTs)	[redacted]	[redacted]	[redacted]	[redacted]	914,000	2018	2039	1,535,138
Blewett CT (4 CTs)	[redacted]	[redacted]	[redacted]	[redacted]	660,000	2018	2024	765,398
Darlington (13 CTs)	[redacted]	[redacted]	[redacted]	[redacted]	4,360,000	2018	2037	6,970,115
H.F. Lee (Wayne County, 5 CTs)	[redacted]	[redacted]	[redacted]	[redacted]	2,950,000	2018	2049	6,342,520
Smith CT (5 CTs)	[redacted]	[redacted]	[redacted]	[redacted]	1,331,000	2018	2041	2,348,697
Sutton Blackstart					2,400,000	2018	2057	6,286,979
Weatherspoon (4 CTs)	[redacted]	[redacted]	[redacted]	[redacted]	3,619,000	2018	2024	4,196,930
Combined Cycle								
Smith CC (PB 4-2x1)	[redacted]	[redacted]	[redacted]	[redacted]	2,573,850	2018	2042	4,655,389
Smith CC (PB 5-2x1)	[redacted]	[redacted]	[redacted]	[redacted]	8,976,150	2018	2051	20,275,784
Sutton (2x1)	[redacted]	[redacted]	[redacted]	[redacted]	574,000	2018	2053	1,362,220
H.F. Lee (3x1)	[redacted]	[redacted]	[redacted]	[redacted]	8,737,000	2018	2052	20,228,969
Total Other Production	[redacted]	[redacted]		[redacted]	**37,095,000**			**74,968,139**
Solar								
Camp Lejeune	[redacted]	[redacted]	[redacted]	[redacted]	820,000	2018	2040	1,411,689
Fayetteville	[redacted]	[redacted]	[redacted]	[redacted]	1,810,000	2018	2040	3,116,044
Elm City	[redacted]	[redacted]	[redacted]	[redacted]	3,917,000	2018	2041	6,911,980
Warsaw	[redacted]	[redacted]	[redacted]	[redacted]	5,244,000	2018	2040	9,027,920
Total Solar	[redacted]	[redacted]	[redacted]	[redacted]	**11,791,000**			**20,467,633**

Source:
Spanos Exhibit 1
DEP Response to PS DR 1-8
DEP Response to PS DR 17-18 Confidential Attachment
DEP Response to PS DR 17-15

Duke Energy Progress
Table 8: Calculation of Weighted Interim Net Salvage Percent
As of December 31, 2018

Account	Estimated Future Interim Retirement	2018 Original Cost as a Percent of Total	DEP Interim Net Salvage %	DEP Weighted Average of Interim Net Salvage (%)	Staff Interim Net Salvage %	Staff Weighted Average of Interim Net Salvage (%)
(1)	(2)	(3)	(4)	(5)=(3)*(4)	(4)	(5)=(3)*(4)
Steam Production						
311.00	6,889,869.26	2.96%	-10%	0%	-10%	0%
312.00	173,517,665.18	74.56%	-15%	-11%	-15%	-11%
314.00	32,294,965.79	13.88%	-25%	-3%	-25%	-3%
315.00	13,542,355.83	5.82%	-10%	-1%	-10%	-1%
316.00	6,482,985.26	2.79%	-2%	0%	-2%	0%
Total Steam Production	**232,727,841.32**			**-15%**		**-15%**
Nuclear Production						
321.00	511,267,740.46	23.28%	-10%	-2%	-10%	-2%
322.00	697,810,955.09	31.78%	-10%	-3%	-10%	-3%
323.00	395,280,145.27	18.00%	-5%	-1%	-5%	-1%
324.00	446,415,737.68	20.33%	-5%	-1%	-5%	-1%
325.00	145,103,738.52	6.61%	-5%	0%	-5%	0%
Total Nuclear Production	**2,195,878,317.02**			**-7%**		**-7%**
Hydro Production						
331.00	1,647,829.44	8.40%	-20%	-2%	-20%	-2%
332.00	4,580,979.84	23.35%	-10%	-2%	-10%	-2%
333.00	6,648,963.72	33.89%	-25%	-8%	-25%	-8%
334.00	5,240,730.39	26.71%	-20%	-5%	-20%	-5%
335.00	1,496,196.22	7.63%	-10%	-1%	-10%	-1%
336.00	5,238.95	0.03%	-1%	0%	-1%	0%
Total Hydro Production	**19,619,938.56**			**-18%**		**-18%**
Other Production						
341.00	63,832,489.46	4.93%	-5%	0%	-5%	0%
342.00	36,454,781.52	2.82%	-5%	0%	-5%	0%
343.00	1,017,587,727.44	78.59%	-5%	-4%	-5%	-4%
344.00	63,592,214.15	4.91%	-10%	0%	-10%	0%
345.00	80,302,603.80	6.20%	-5%	0%	-5%	0%
346.00	33,112,243.59	2.56%	-1%	0%	-1%	0%
Total Other Production	**1,294,882,059.96**			**-4%**		**-4%**
Solar Production						
341.20	6,943.40	0.01%	0%	0%	0%	0%
344.20	87,310,391.11	97.54%	0%	0%	0%	0%
345.20	2,186,623.93	2.44%	0%	0%	0%	0%
346.20	6,378.91	0.01%	0%	0%	0%	0%
Total Solar Production	**89,510,337.35**			**0%**		**0%**

DEP Response to PS DR 17-17

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 17

Docket No. E-2, Sub 1219

Date of Request: **November 14, 2019**
Date of Response: **November 25, 2019**

X	**CONFIDENTIAL**
	NOT CONFIDENTIAL

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached Confidential response to NC Public Staff Data Request No. 17-18, was provided to me by the following individual(s): Melissa Brammer Abernathy, Manager, Accounting II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Senior Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 17
DEP Docket No. E-2, Sub 1219
Item No. 17-18
Page 1 of 1

Request:

18. Direct Testimony of John S. Spanos, page 14, lines 14-15, discusses decommissioning studies performed by Burns and McDonnell. Please provide the decommissioning studies referenced.

Confidential Response:

[redacted]

[redacted]

[redacted]

Docket No. E-2, Sub 1219

Confidential Pages 3 - 75 not included

Public Staff's Testimony of

Roxie McCullar, Consultant
William Dunkel & Associates

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 17

Docket No. E-2, Sub 1219

Date of Request:	**November 14, 2019**
Date of Response:	**November 25, 2019**

[X] **CONFIDENTIAL**

[ ] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached Confidential response to NC Public Staff Data Request No. 17-10, was provided to me by the following individual(s): Melissa Brammer Abernathy, Manager, Accounting II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Senior Counsel
Duke Energy Progress

Pursuant to communications with DEP Counsel on March 19, 2020,
DEP has waived confidentiality of the responses to PSDR 17-10 (a.) and (b.)
/S Tim Dodge, Staff Attorney, Public Staff

North Carolina Public Staff
Data Request No. 17
DEP Docket No. E-2, Sub 1219
Item No. 17-10
Page 1 of 1

Request:

10. Page IX-178 of Spanos Exhibit 1 (2018 Depreciation Study) shows the detailed depreciation calculation for Account 370.02 Meters, Utility of the Future.
a. Please provide a description of the “Utility of the Future” equipment included in this account.
b. Please provide any information the company received regarding the warranty or expected life of the equipment included in this account.
c. Please provide any documents that support the response to part (b) of this request.

Response:

a. The equipment in this account is the Itron Advanced Metering Infrastructure (“AMI”) meters and associated equipment installed through AMI projects.

b. The equipment included in the scaled deployments of Itron OpenWay AMI meters have a three-year warranty on the meters, and an expected service life of 15-20 years. The Company believes that a fifteen-year average depreciable life is appropriate given the type of asset, trends in the utility industry for new meters, pace of technology advancement, the reliance on computers and sensors in the AMI meters and the expected life characteristics of the primary components of the new meters. A 17-year average service life was approved as part of the settlement for DEP’s last rate case.

c. Please see the attachment “PS DR 17-10 Attachment – CONFIDENTIAL”.

PS DR 17-9c
Attachment - CONFI

Pursuant to communications with DEP Counsel on March 19, 2020,
DEP has waived confidentiality of the responses to PSDR 17-10 (a.) and (b.)
/S Tim Dodge, Staff Attorney, Public Staff

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
PS DR 17-9c

Confidenital – [redacted]

[redacted]

[redacted]

[redacted]

Analysis of COS Methodologies

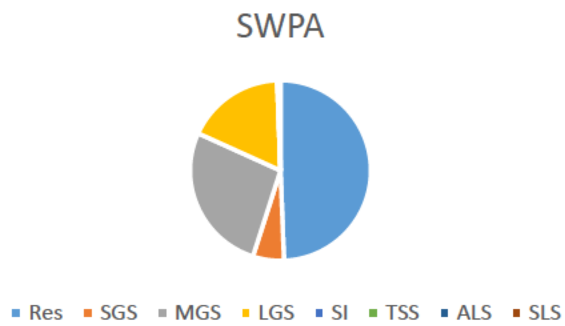
Total Energy Requirements by Jurisdiction and Customer Class

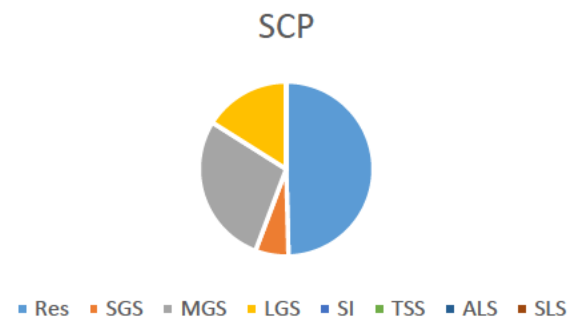
	System	NC Retail	Residential	SGS	MGS	LGS	SI	TSS	ALS	SLS
Energy (GWH)	65,949	40,301	17,417	2,072	11,663	8,729	45	5	280	90
System	100%	61.11%								
NC Retail		100%	43.22%	5.14%	28.94%	21.66%	0.11%	0.01%	0.69%	0.22%

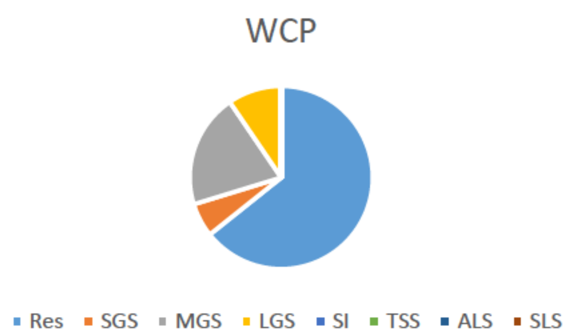
Allocation of Production Plant by COSS Methodology

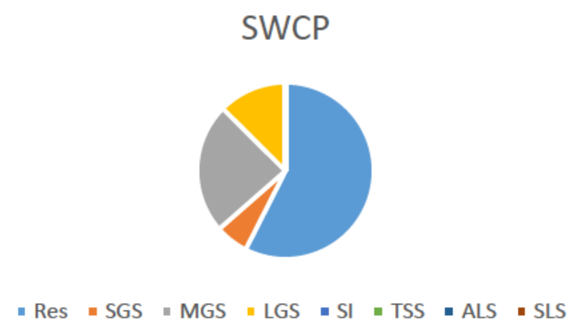
	System	NC Retail	Residential	SGS	MGS	LGS	SI	TSS	ALS	SLS
SWPA										
System	100%	60.86%								
NC Retail		100%	49.38%	5.56%	26.82%	17.63%	0.09%	0.01%	0.38%	0.12%
SCP										
System	100%	61.53%								
NC Retail		100%	49.60%	6.16%	28.18%	15.99%	0.07%	0.01%	0.00%	0.00%
WCP										
System	100%	59.59%								
NC Retail		100%	64.30%	5.99%	20.21%	9.46%	0.04%	0.01%	0.00%	0.00%
SWCP										
System	100%	60.48%								
NC Retail		100%	57.47%	6.07%	23.91%	12.49%	0.05%	0.01%	0.00%	0.00%
4CP										
System	100%	60.84%								
NC Retail		100%	53.78%	6.07%	25.84%	14.22%	0.08%	0.01%	0.00%	0.00%
12CP										
System	100%	61.61%								
NC Retail		100%	52.40%	5.85%	26.47%	15.18%	0.11%	0.01%	0.00%	0.00%

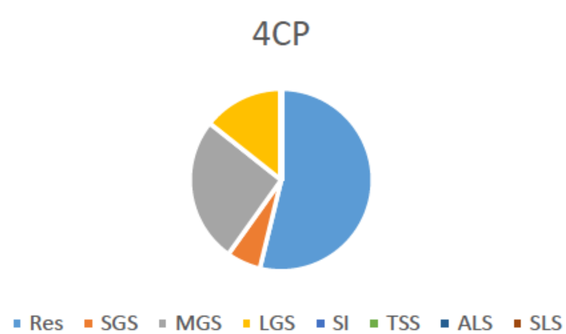
Analysis of COS Methodologies

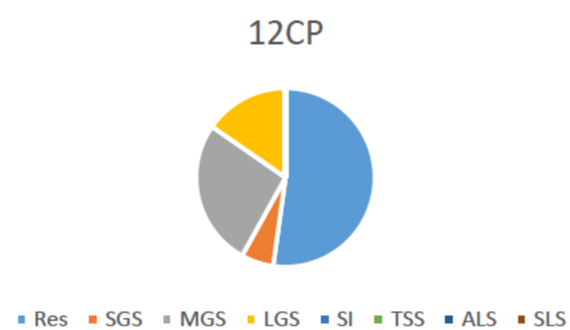








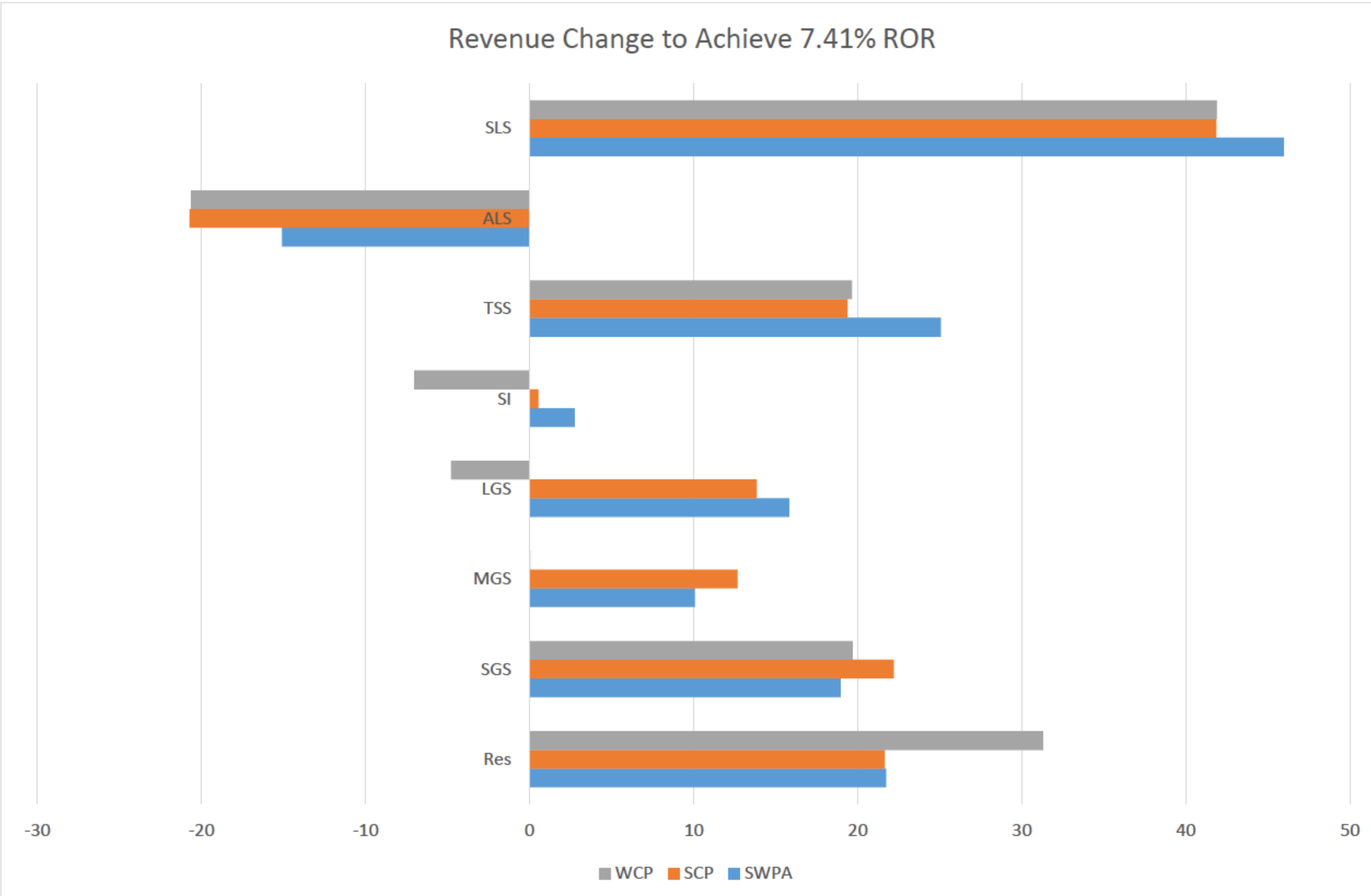




Rates of Return and Revenue Increases for SWPA, SCP, and WCP COS Methodologies

Rate of Return and % Increase	**NC Retail**	**RES**	**SGS**	**MGS**	**LGS**	**SI**	**TSS**	**ALS**	**SLS**
					SWPA				
Present Revenues Annualized ROR	3.40%	2.74%	3.24%	4.82%	2.80%	7.44%	1.05%	12.36%	1.67%
Proposed Revenues ROR	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%
Revenue Increase to achieve 7.41%	17.15%	21.72%	18.95%	10.07%	15.83%	2.75%	25.07%	-15.10%	45.98%
					SCP				
Present Revenues Annualized ROR	3.30%	2.74%	2.52%	4.00%	3.44%	8.18%	2.35%	14.64%	2.15%
Proposed Revenues ROR	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%
Revenue Increase to achieve 7.41%	17.55%	21.64%	22.20%	12.68%	13.85%	0.52%	19.39%	-20.74%	41.86%
					WCP				
Present Revenues Annualized ROR	3.57%	1.16%	2.94%	8.38%	10.58%	10.88%	2.32%	14.66%	2.15%
Proposed Revenues ROR	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%	7.41%
Revenue Increase to achieve 7.41%	16.45%	31.29%	19.69%	0.03%	-4.18%	-7.03%	19.64%	-20.64%	41.89%

Rates of Return and Revenue Increases for SWPA, SCP, and WCP COS Methodologies



Public Staff
Garrett Exhibit 9

Independent Development Cost Estimate for Brickhaven Stuctural Fill

Cost Category	Source for Basis Amount	Basis Amount	Adjusted Amount	Comments
Land Acquisition	Chatham County Tax Records	$ 11,873,700	$ 13,654,755	Add 15% for Acquisition Cost
Rail/Infrastructure	Original Amounts in Sutton & Riverbend Purchase Orders	$ 18,000,000	$ 27,000,000	Add 50% Contingency for Brickhaven Site
Mining Bond	Mine Permit	$ 500,000	$ 500,000	No Adjustment
Closure Cost	Financial Assurance Documents	$ 9,520,000	$ 9,520,000	Average $/acre cost in Closure Cost Estimate; 68 Acre area
Post Closure Cost	Financial Assurance Documents	$ 1,038,889	$ 1,038,889	68 acres/144 acres X $2,220,000 Post Closure Cost Amount
Cell Development	Estimate	$ 30,600,000	$ 30,600,000	$450,000/acre; 68 acre area
	Total	$ 71,532,589	$ 82,313,644	

No. 271A18 & 401A18

SUPREME COURT OF NORTH CAROLINA

* *

STATE OF NORTH CAROLINA ex rel. UTILITIES COMMISSION; DUKE ENERGY PROGRESS, LLC, Applicant, Appellees, v. ATTORNEY GENERAL JOSHUA H. STEIN, Intervenor; SIERRA CLUB, Intervenor, Appellants, PUBLIC STAFF—NORTH CAROLINA UTILITIES COMMISSION, Intervenor, Cross-Appellant.	<u>From the North Carolina Utilities Commission</u>
STATE OF NORTH CAROLINA ex rel. UTILITIES COMMISSION; DUKE ENERGY CAROLINAS, LLC, Applicant, Appellees, v. ATTORNEY GENERAL JOSHUA H. STEIN, Intervenor; SIERRA CLUB, Intervenor; NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, Intervenor; NORTH CAROLINA JUSTICE CENTER, NORTH	<u>From the North Carolina Utilities Commission</u>

CAROLINA HOUSING COALITION,
NATURAL RESOURCES DEFENSE COUNCIL,
and SOUTHERN ALLIANCE FOR CLEAN
ENERGY, Intervenors,

Appellants,

PUBLIC STAFF—NORTH CAROLINA
UTILITIES COMMISSION, Intervenor,

Cross-Appellant.

* *

AMICUS CURIAE BRIEF OF THE NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY

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INDEX

TABLE OF CASES AND AUTHORITIES

STATUTES

REGULATIONS

SESSION LAWS

No. 271A18 & 401A18

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UTILITIES COMMISSION, Intervenor,

Cross-Appellant.

* *

AMICUS CURIAE BRIEF OF THE NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY

* *

ISSUES PRESENTED

1. DID THE UTILITIES COMMISSION CORRECTLY INTERPRET THE GROUNDWATER RULES, IN PARTICULAR REGARDING WHEN A VIOLATION OF THE 2L STANDARDS OCCURS?

2. DID THE UTILITIES COMMISSION CORRECTLY INTERPRET THE COAL ASH MANAGEMENT ACT, IN PARTICULAR REGARDING THE TRIGGER FOR MONITORING, ASSESSMENTS AND CORRECTIVE ACTION UNDER THE ACT?

INTRODUCTION AND SUMMARY[1]

Amicus curiae the North Carolina Department of Environmental Quality (the "Department") requested leave to submit this brief to expound on two aspects of the orders under review in these consolidated cases.[2] As discussed below, the Utilities Commission has misconstrued two separate provisions of law that are integral to the Department implementing its mandate to protect the state's vital groundwater resources from contamination.

First, the Utilities Commission indicated that an exceedance of the groundwater standards that triggers a regulatory requirement for corrective action may not be a "violation" of law so long as the responsible party is diligently conducting remediation. If that were the case, the Department would be stripped of certain of its enforcement powers regarding these

---

[1] Pursuant to Appellate Rule 28(i)(2), the amicus represents that this brief was prepared by the amicus and its counsel with no monetary or other contributions from any other persons or entities.

[2] For consistency with previous briefs, the Department will refer to Duke Energy Progress and Duke Energy Carolinas as Progress and Carolinas, respectively, and as Duke collectively, with the two orders at issue being referred to as the Progress order (Progress R pp 477-754) and the Carolinas order (Carolinas R pp 825-1226).

exceedances. But it is not correct. Exceedances of the groundwater standards that occur at or beyond established distances from a facility are violations, regardless of whether the responsible party is engaged in corrective action. It is these violations that obligate the responsible party to assess and remedy the violations, and also authorize the Department to take enforcement action.

Second, the Utilities Commission opined that the groundwater assessment and corrective action requirements under the Coal Ash Management Act are triggered by exceedances of groundwater standards. This is incorrect. The assessment and remediation requirements under this act result from mere ownership of a coal combustion residuals surface impoundment.

The Department respectfully urges the Court that, should it be necessary to opine on these issues, the Court's opinion accord with the law as explained below.

ARGUMENT

I. AN EXCEEDANCE OF A GROUNDWATER STANDARD THAT OCCURS AT OR BEYOND THE COMPLIANCE BOUNDARY IS A VIOLATION AND REQUIRES ASSESSMENT AND CORRECTIVE ACTION BY THE RESPONSIBLE PARTY.

The General Assembly has tasked the Environmental Management Commission ("EMC") and the Department with the responsibility to protect the groundwater in the state. To that end, the EMC has adopted rules that establish maximum allowable groundwater concentrations for nearly 150 chemicals, including carcinogens and acute toxins. 15A N.C. Admin. Code 2L .0202 (hereinafter "2L standards"). The EMC has also adopted a robust regime to ensure that violations of those standards are expeditiously identified and remedied. Id. r. 2L .0101 et seq. (the "Groundwater Rules"). The EMC, in turn, has authorized the Department to oversee the Groundwater Rules, id., and the General Assembly has vested the Secretary of Environmental Quality with the authority to enforce those rules, N.C. Gen. Stat. § 143-215.6A(a)(1), (6).

When a violation of these standards occurs, the rules mandate that the responsible party assess the situation and remedy the violation. However, in the orders under review in this case, the Utilities Commission indicated that so long as the responsible party is complying with the assessment and correction action requirements, the party may not be in violation of the standard. (Carolinas R pp 1121-23; Progress R pp 653-55) As demonstrated below, this is incorrect.

A. The finding of a violation of the 2L standards triggers the assessment and remediation requirements.

The Groundwater Rules are clear that any "increase in the concentration of a substance" to a level above a 2L standard may be a "violation." 15A N.C. Admin. Code 2L .0106(c)-(e). But whether such a concentration is a "violation" and not a mere "exceedance" depends on the circumstances.

The rules differentiate between facilities that have individual permits issued under N.C. Gen. Stat. § 143-215.1 or chapter 130A and those that do not. Facilities with such individual permits have a "compliance boundary." See id. r. 2L .0101(3), .0107. A compliance boundary is a perimeter established by rule around a permitted facility. Exceedances of 2L standards are allowed inside this perimeter. However, if the permitted activity "results in an increase in the concentration of a substance in excess of the standards at or beyond the compliance boundary," the permittee must "notify the Department" "of the violation." Id. r. 2L .0106(e) (emphasis added); see also id. r. 2L .0106(d). In addition, the permittee must submit a report that assesses "the cause, significance, and extent of the violation." Id. (emphasis added).

For activities that lack permits, when the activity "results in an increase in the concentration of a substance in excess of the standard," the person conducting the activity must "notify the Department" "of the violation" and report to the Department on "the cause, significance, and extent of the violation." Id. r. 2L .0106(c) (emphasis added). There is no compliance boundary and therefore no geographic limit for violations caused by activities that lack permits. See id.

By contrast, an "exceedance" occurs when the concentration of a substance is greater than the 2L standard. The existence of an exceedance is a factual determination, and does not necessarily indicate a violation.

The rules regarding "review boundaries" elucidate the distinction between violations and exceedances. Certain permitted facilities have a "review boundary" that is enclosed within the compliance boundary. 15A N.C. Admin. Code 2L .0102(20). The purpose of the review boundary is to identify problems before they manifest at the compliance boundary. "When the concentration of any substance equals or exceeds the standard at the review boundary" the permittee must take steps to ensure that the exceedance does not reach the compliance boundary. Id. r. 2L .0106(d)(1), .0108 (emphasis added). Only if the exceedance were to migrate to the compliance boundary would it then constitute "a violation." Id. r. 2L .0106(d)(1). That is, an exceedance that occurs within the compliance boundary is not a violation.

In some areas, contaminants may naturally be present in the groundwater at levels above the concentrations listed in rule 2L .0202. The rules define the regulatory standard as the greater of the specific numeric standard listed in 2L .0202 or naturally occurring concentrations. Id. r. 2L .0202(b)(3). In this way, the rules ensure that nobody can be held liable for naturally occurring concentrations of contaminants.

Accordingly, a violation occurs at a permitted facility if the permitted activity causes contaminant levels at or beyond the compliance boundary that exceed the 2L standards. For an unpermitted activity, a violation occurs if the activity results in an exceedance of the 2L standard anywhere.

B. Compliance with the assessment and remediation requirements does not negate the existence of a 2L violation.

In its orders, the Utilities Commission discussed Duke's compliance with the Groundwater Rules. In these discussions, the Commission properly recognized that there is a difference between an exceedance of the 2L standards and a violation of the Groundwater Rules. However, the Commission drew that line in the wrong place.

As the discussion above indicates, an exceedance is a violation of a 2L standard if it occurs at or beyond the compliance boundary. However, in the Carolinas and Progress orders at issue here, the Commission indicates that so long as the exceedance is being properly addressed through the remediation process, then no violation has occurred. This contradicts the controlling regulations.

In the Carolinas order, the Utilities Commission "agree[d]" with and gave "substantial weight" to the following testimony of Carolinas' witness James Wells:

> [E]ven when an exceedance requires corrective action, the groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated . . . the permittee is immediately subject to an NOV and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. [Citation omitted]
>
> Witness Wells contrasted this process with groundwater standards, under which an exceedance does not immediately result in an NOV and escalating penalty. Instead, he explained the owner/operator must report the exceedance and work with the DEQ to determine whether

> it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. . . . He testified that the 2L rules' corrective action provisions are deliberately designed around the idea that older facilities, built before liners were a regulatory obligation, were likely to have associated groundwater impacts, that such impacts were not the result of regulatory noncompliance, and that they should be addressed in a measured process. He concluded that compliance with this process is not mismanagement and should not be held against [Carolinas] with respect to cost recovery. [Citation omitted]

(Carolinas R pp 833, 1122-23)

The gist of this testimony is that an exceedance is not a violation so long as corrective action is being undertaken. This testimony misapplies the law.

Most tellingly, Witness Wells incorrectly restated critical language in the Groundwater Rules. Witness Wells explained in the passage above that upon the detection of an exceedance, the "owner/operator must . . . assess the extent of the <u>exceedance</u>." (Carolinas R p 1122 (emphasis added)) That is inaccurate. The Groundwater Rules mandate instead that in such circumstances, the owner/operator must "assess[] the . . . extent of the <u>violation</u>." <u>E.g.</u>, 15A N.C. Admin. Code 2L .0106(e)(3) (emphasis added).

The contrast with enforcement procedures under federal law also fails to show that an exceedance for which corrective action is underway is not a violation. Whether an enforcement agency chooses to enforce immediately or to defer enforcement does not inform whether a violation has occurred. It only speaks to the agency's enforcement discretion, not its authority.

On this subject, Witness Wells also recounted a 2011 Department memorandum, which was rescinded by the Department in late 2015. (See Carolinas Doc. Ex. 9902, 10714-16; Progress Doc. Ex. 3822) He correctly summarized that pursuant to the 2011 memorandum, "only after a utility failed to undertake corrective action when directed to do so would DEQ consider pursuing enforcement." (Carolinas R p 1122) But the memorandum clarified that "[i]f the permitted facility is determined to be in non-compliance . . . adherence to the corrective action requirements specified in 15A NCAC 2L .0106 will be required." Put another way, "non-compliance," i.e., a violation, is not the result of a failed corrective action; it is instead a necessary precursor to the requirement to undertake corrective action.[3] (Carolinas Doc. Ex. 10715)

[3] At one point, the Commission appears to recognize that the "corrective action provisions" in the Groundwater Rules are "triggered by . . . violations." (Carolinas R p 1123 (emphasis in original)) This does not clarify the issue but only further muddies the waters as to the Commission's position.

Further, Witness Wells testified that "older facilities" that were "built before liners were a regulatory obligation . . . should be addressed in a measured process." (Carolinas R p 1123) To the extent that this concept of a "measured process" imports the notion that an exceedance at or beyond the compliance boundary is not a violation, it incorrectly states the law.

At several other points, the Commission's discussion similarly appeared to veer significantly from the proper interpretation of the Groundwater Rules. First, the Commission stated that, under the 2015 settlement between Duke and the Department, "there was a very serious question as to whether any violation of the State's groundwater standards had occurred." (Carolinas R p 1121) This is inaccurate. The 2015 settlement specifically states that "Duke Energy submitted monitoring that showed exceedances of the State's groundwater standards at or beyond the compliance boundary at the Asheville Plant." (Carolinas Doc. Ex. 2086) A simple application of the Groundwater Rules shows that there was no question that a violation had occurred.[4] In fact, a later superior court

[4] The 2015 settlement even recounts that the Department "sent Duke Energy a Notice of Violation . . . based upon groundwater monitoring results

judgment ordered Duke to take significant steps to "remedy[] the violations" that the Department had brought to the court's attention. (Carolinas Doc. Ex. 9969)

Second, the Utilities Commission appears to have agreed with Witness Wells that "exceedances of groundwater standards . . . do not indicate mismanagement or poor compliance programs" because they are "rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed." (Carolinas R p 1121) Any suggestion here that "the existence of groundwater exceedances at or beyond the compliance boundaries" are not violations, i.e., "poor compliance," would be inaccurate.

. . . for the Asheville Plant." (Carolinas Doc. Ex. 2086) This notice was later withdrawn in order to facilitate the settlement of a contested case filed by Duke. (Id. at 2090)

By entering into the 2015 settlement, the Department agreed not to, for example, "file any judicial action against" Duke regarding groundwater monitoring or groundwater conditions at Duke's coal ash sites. (Carolinas Doc. Ex. 2090) To be clear, even if this amicus brief were a "fil[ing]" of a "judicial action," it is not made "against Duke." The Department does not take a position on the outcome of this litigation. The Department offers this brief to apprise the Court of its interpretation of the Groundwater Rules and a limited provision of Coal Ash Management Act in order to ensure that no inadvertent violence is done to these provisions in this litigation.

Indeed, "the existence of groundwater exceedances at or beyond the compliance boundaries" is a violation of the 2L standards by definition.

The Court can see here, again, the attempt to hinge the determination of whether a violation has occurred on compliance with "groundwater assessment and correction action." And again, the Court should reject that effort. "[G]roundwater assessment and correction action" are legal requirements that flow from the existence of a violation of the 2L standards. They are not themselves used to determine whether a violation has occurred.

It is irrelevant in this context that, as the Utilities Commission noted, "requirements changed over time." (Carolinas R p 1121) The fact that any party may have failed to conform itself to new standards once those standards became enforceable does not negate any violations of those new standards.

Third, the Utilities Commission made these same missteps in the Progress order. For example, the Commission approved of the notion that "groundwater impacts" from "older facilities, built before liners were a regulatory obligation . . . should be addressed in a measured process" (Progress R p 653), which incorrectly implies that an exceedance at or beyond the compliance boundary is not necessarily a violation. Similarly, and equally as problematic, the Commission in the Progress order recapped with approval Witness Wells' testimony that "exceedances of groundwater standards" were merely "a function of where these sites are on the timeline of groundwater assessment and corrective action" and therefore not indicative of "poor compliance." (Id.; see also id. at 654-55 (repeating the discussion of the Department's 2011 memorandum))

The import of the distinction between an "exceedance" and a "violation" is not limited to leaky coal ash ponds. The Groundwater Rules apply to any type of operation that may cause contamination of groundwater, such as fuel service stations, quarries, landfills, manufacturing facilities, etc. 15A N.C. Admin. Code 2L .0106(c)-(e) (applying requirements to "[a]ny person conducting or controlling an activity").

The Secretary may assess a penalty "against any person who . . . [v]iolates" a 2L standard. See N.C. Gen. Stat. § 143-215.6A(a)(1). The Secretary may also penalize one who "[v]iolates a rule of the [Environmental Management] Commission," such as the Groundwater Rules. Id. § 143-215.6A(a)(6). For "continuous" actions, penalties may reach "twenty-five thousand dollars ($ 25,000) per day for so long as the violation continues."

Id. § 143-215.6A(b).[5] If an entity were determined to be in compliance with the Groundwater Rules simply because it was following through on its obligations to assess and remediate violations, the Department's ability to penalize wrongdoers could be eviscerated and an effective deterrent would be lost.

For all of these reasons, should the Court find it necessary to opine on the issue, the Court should confirm that an exceedance of a 2L standard (including background concentrations) that occurs at or beyond a compliance boundary (if one exists) is a violation that subjects the violator to available enforcement mechanisms.

II. THE ASSESSMENT AND CORRECTIVE ACTION REQUIREMENTS UNDER THE COAL ASH MANAGEMENT ACT ARE NOT PREDICATED ON AN EXCEEDANCE OF A 2L STANDARD.

The Utilities Commission also misinterpreted a critical provision of the Coal Ash Management Act of 2014. N.C. Gen. Stat. § 130A-309.200 et seq. In the Carolinas order, the Commission stated that "one key difference

[5] Criminal sanctions may also flow from "violat[ion]s" of "standards . . . established in rules adopted by the [Environmental Management] Commission." Id. § 143-215.6B(f)-(h). Likewise, the Department may seek injunctive relief if it believes "that any person has violated" the Groundwater Rules and the 2L standards. Id. § 143-215.6C.

between" the act and the Groundwater Rules "is that [the act]'s groundwater assessment and corrective action provisions are triggered by <u>exceedances</u> – not <u>violations</u> – of the 2L groundwater standards." (Carolinas R p 1123 (footnote omitted)) This inaccurately sets forth the trigger under the act.

The Groundwater Rules require assessment and remediation of groundwater contamination if an "activity . . . results in" an exceedance "at or beyond the compliance boundary," which is by rule "a violation." 15A N.C. Admin. Code 2L .0106(e). The Coal Ash Management Act does not use an analogous trigger tied to an exceedance. Instead, the act requires assessment and remediation at all coal combustion residuals surface impoundments, regardless of whether an exceedance or a violation as occurred.

Section 130A-309.211[6] of the Coal Ash Management Act provides that "[t]he owner of a coal combustion residuals surface impoundment shall conduct groundwater monitoring and assessment as provided in this subsection" and "implement corrective action for the restoration of

---

[6] Section 130A-309.211 was originally enacted in 2014 as section 130A-309.209. Coal Ash Management Act of 2014, ch. 122, § 3(a), 2014 N.C. Sess. Laws 828, 838-40 (enacting N.C. Gen. Stat. § 130A-309.209) (<u>See also</u> Progress Doc. Ex. 950-52). It was recodified as section 130A-309.211 in 2016. Act of July 14, 2016, ch. 95, § 1, 2016 N.C. Sess. Laws ___, ___.

groundwater quality as provided in this subsection." N.C. Gen. Stat. § 130A-309.211(a)-(b). There is no requirement that any exceedance or violation occur or be identified before any party is mandated to "conduct groundwater monitoring and assessment" and "implement corrective action." The mere fact that a party is an "owner of a coal combustion residuals surface impoundment" triggers the obligation to monitor, assess, and implement corrective action.

Therefore, the Commission's conclusion that the Coal Ash Management Act's "groundwater assessment and corrective action provisions are triggered by exceedances" (Carolinas R p 1123) is contrary to the plain language in the statute.

CONCLUSION

For the foregoing reasons, the Court should (1) interpret the Groundwater Rules to indicate that an exceedance of a 2L standard (including background concentrations) at or beyond the applicable compliance boundary is a violation that subjects the violator to available enforcement mechanisms regardless of any ongoing corrective action, and (2) interpret the Coal Ash Management Act to require each "owner of a coal combustion residuals surface impoundment" to conduct monitoring, assessment, and corrective action regardless of any exceedances.

Respectfully submitted this the 25th day of September, 2019.

NORTH CAROLINA
DEPARTMENT OF JUSTICE,
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N.C. App. R. 33(b) Certification: I certify that the attorneys listed below have authorized me to list their names on this brief as if they had personally signed.

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CERTIFICATE OF COMPLIANCE

I certify that, pursuant to Appellate Rule 28(j), this brief (excluding the parts omitted by rule from the calculation) contains fewer than 3,750 words.

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September 25, 2019

CERTIFICATE OF SERVICE

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Special Deputy Attorney General

September 25, 2019

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Saillor Exhibit 1

Docket No. E-2, Sub 1219

Calculation of Weather Normalization Revenue Adjustment

(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	Revenue Adjustment[2] (d) = (b) × (c) ÷ 100,000
Residential	(610,804,624)	8.8115	$ (53,821)
Small General	(29,797,487)	8.7198	(2,598)
Medium General	(172,201,436)	7.0942	(12,216)
Large General	(41,103,239)	5.5487	(2,281)
Total NC Retail	(853,906,786)		$ (70,916)

Note 1: Average customer class rates are based on annualized revenues, excluding revenues from basic facilities charges, divided by per book sales.

Public Staff
Saillor Exhibit 2

Docket No. E-2, Sub 1219

Monthly NC Retail kWh Weather Adjustments updated through December 2019

North Carolina* Weather Adjustments

Month	Year	Residential	Small General	Medium General	Large General
Jan	2018	(277,633,426)	(5,966,742)	(30,539,594)	(12,579,330)
Feb	2018	225,105,368	461,015	2,120,601	1,244,056
Mar	2018	161,103,085	142,390	14,684,971	52,042,570
Apr	2018	(84,082,596)	(71,258)	(7,346,660)	(20,446,878)
May	2018	(22,271,530)	(1,241,617)	(8,752,917)	(10,134,073)
Jun	2018	(159,044,695)	(11,932,161)	(58,697,494)	(22,367,923)
Jul	2018	(81,052,707)	(4,977,145)	(42,064,378)	(61,788,926)
Aug	2018	21,448,088	1,540,594	8,214,131	5,031,099
Sep	2018	(110,516,192)	4,537,973	42,564,812	67,765,203
Oct	2018	(190,233,849)	(17,042,233)	(98,312,644)	(67,199,239)
Nov	2018	(6,471,760)	(16,802,148)	(97,483,325)	(46,655,568)
Dec	2018	(87,154,412)	21,553,846	103,411,062	73,985,770
Total		(610,804,624)	(29,797,487)	(172,201,436)	(41,103,239)

*Values were generated using the monthly historical ratio of NC actual billed sales to actual billed sales (NC/System)

Public Staff
Saillor Exhibit 3

Docket No. E-2, Sub 1219

Customer Growth and Change in Usage kWh Adjustments through December 31, 2019

Rate Class	Per Book kWh Sales	Test Year Number of Bills	Number of Bills at End of Period	Change in # of Bills[1]	Customer Growth kWh Adjustment	Change in Usage kWh Adjustment	Adjusted Per Book kWh Sales
Residential	16,666,046,589	14,562,331	14,922,972	360,641	409,238,802	(310,690,124)	16,764,595,267
Small General	1,982,596,401	2,006,644	2,036,376	29,732	28,346,660	(60,114,262)	1,950,828,799
Medium General	11,178,964,878	463,385	462,935	(450)	231,503,753	(226,089,910)	11,184,378,722
Large General	8,500,866,335	3,451	3,636	185	146,807,122	(65,913,809)	8,581,759,648
Street Lighting	85,107,971	2,318,787	2,343,660	24,873	915,635	-	86,023,606
Sports Field Lighting	1,134,908	946	972	26	23,431	20,245	1,178,584
Traffic Signal Lighting	4,754,792	63,311	63,432	121	9,235	-	4,764,027
Total NC Retail	38,419,471,874				816,844,638	(662,787,860)	38,573,528,652

Note 1: For the MGS and LGS customer classes, the change in the number of bills equals the number of bills added for new accounts minus the number of bills removed for closed accounts.

Public Staff
Saillor Exhibit 4

Docket No. E-2, Sub 1219

Calculation of Customer Growth Revenue Adjustment

(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	BFC Revenues[2] (d)	Revenue Adjustment (e) = (b) × (c) ÷ 100,000 + (d)
Residential excluding TOU	401,416,124	8.8508	$ 4,952	$ 40,481
Residential TOU	7,822,678	8.6959	$ 116	$ 796
Total Residential	409,238,802			$ 41,278
SGS excluding Constant Load Rate	27,320,655	10.8139		$ 2,954
SGS Constant Load Rate	1,026,005	11.1968		$ 115
Total Small General Service	28,346,660			$ 3,069
Medium General Service	97,394,300	8.7319		$ 8,504
SGS Time of Use	129,131,822	6.7230		$ 8,682
Seasonal and Intermittent Service	4,977,632	10.9476		$ 545
Total Medium General Service	231,503,753			$ 17,731
LGS excluding TOU and RTP	44,395,281	6.9225		$ 3,073
LGS Time of Use	61,043,511	6.2937		$ 3,842
LGS Real Time Pricing	41,368,330	5.0816		$ 2,102
Total Large General Service	146,807,122			$ 9,017
Sports Field Lighting	23,431	17.8052		$ 4
Street Lighting	915,635	30.8441		$ 282
Traffic Signal Lighting	9,235	9.1477		$ 1
Total NC Retail	816,844,638			$ 71,382

Note 1: Average customer class rates are based on annualized revenues divided by per book sales.

Note 2: For Residential customers, revenues from Basic Facilities Charges are calculated separately.

Public Staff
Saillor Exhibit 5

Docket No. E-2, Sub 1219

Calculation of Change in Usage Revenue Adjustment

(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	Revenue Adjustment (d) = (b) × (c) ÷ 100,000
Residential excluding TOU	(304,751,223)	8.8508	$ (26,973)
Residential TOU	(5,938,901)	8.6959	$ (516)
Total Residential	(310,690,124)		$ (27,489)
SGS excluding Constant Load Rate	(57,938,430)	8.7576	$ (5,074)
SGS Constant Load Rate	(2,175,831)	6.3875	$ (139)
Total Small General Service	(60,114,262)		$ (5,213)
Medium General Service	(95,116,680)	8.5298	$ (8,113)
SGS Time of Use	(126,112,002)	6.6149	$ (8,342)
Seasonal and Intermittent Service	(4,861,227)	10.4174	$ (506)
Total Medium General Service	(226,089,910)		$ (16,962)
LGS excluding TOU and RTP	(19,932,698)	6.9033	$ (1,376)
LGS Time of Use	(27,407,460)	6.2644	$ (1,717)
LGS Real Time Pricing	(18,573,651)	5.0783	$ (943)
Total Large General Service	(65,913,809)		$ (4,036)
Sports Field Lighting	20,245	15.4594	$ 3
Street Lighting	-	30.8441	$ -
Traffic Signal Lighting	-	9.1477	$ -
Total NC Retail	(662,787,860)		$ (53,697)

Note 1: Average customer class rates are based on annualized revenues, excluding revenues from basic facilities charges, divided by per book sales.

Public Staff
Saillor Exhibit 1

Docket No. E-2, Sub 1219

Customer Growth and Change in Usage kWh Adjustments - Second Settlement

Rate Class	Per Book kWh Sales	Test Year Number of Bills	Number of Bills at End of Period	Change in # of Bills[1]	Customer Growth kWh Adjustment	Change in Usage kWh Adjustment	Adjusted Per Book kWh Sales
Residential	16,666,046,589	14,562,331	15,036,909	474,578	534,727,318	(360,007,333)	16,840,766,574
Small General	1,982,596,401	2,006,644	2,045,202	38,558	36,733,350	(118,908,337)	1,900,421,414
Medium General	11,222,040,191	471,089	466,114	(4,975)	104,709,270	(485,222,212)	10,841,527,249
Large General	8,457,791,022	3,451	3,555	104	99,541,828	(32,988,171)	8,524,344,679
Street Lighting	85,107,971	2,318,787	2,386,731	67,944	2,498,494	-	87,606,465
Sports Field Lighting	1,134,908	946	975	29	27,006	(77,824)	1,084,090
Traffic Signal Lighting	4,754,792	63,311	62,553	(758)	(56,837)	-	4,697,956
Total NC Retail	38,419,471,874				778,180,431	(997,203,877)	38,200,448,428

Note 1: For the MGS and LGS customer classes, the change in the number of bills equals the number of bills added for new accounts minus the number of bills removed for closed accounts.

Public Staff
Saillor Exhibit 2

Docket No. E-2, Sub 1219

Calculation of Customer Growth Revenue Adjustment
(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	BCC Revenues[2] (d)	Revenue Adjustment (e) = (b) × (c) ÷ 100,000 + (d)
Residential excluding TOU	524,505,903	8.8508	$ 6,517	$ 52,940
Residential TOU	10,221,415	8.6959	$ 153	$ 1,042
Total Residential	534,727,318			$ 53,982
SGS excluding Constant Load Rate	35,403,789	10.8139		$ 3,829
SGS Constant Load Rate	1,329,561	11.1968		$ 149
Total Small General Service	36,733,350			$ 3,977
Medium General Service	44,051,494	8.7319		$ 3,847
SGS Time of Use	58,406,391	6.7230		$ 3,927
Seasonal and Intermittent Service	2,251,386	10.9476		$ 246
Total Medium General Service	104,709,270			$ 8,020
LGS excluding TOU and RTP	30,101,996	6.9225		$ 2,084
LGS Time of Use	41,390,245	6.2937		$ 2,605
LGS Real Time Pricing	28,049,587	5.0816		$ 1,425
Total Large General Service	99,541,828			$ 6,114
Sports Field Lighting	27,006	17.8052		$ 5
Street Lighting	2,498,494	30.8441		$ 771
Traffic Signal Lighting	(56,837)	9.1477		$ (5)
Total NC Retail	778,180,431			$ 72,863

Note 1: Average customer class rates are based on annualized revenues divided by per book sales.

Note 2: For Residential customers, revenues from Basic Customer Charges are calculated separately.

Public Staff
Saillor Exhibit 3

Docket No. E-2, Sub 1219

Calculation of Change in Usage Revenue Adjustment
(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	Revenue Adjustment (d) = (b) × (c) ÷ 100,000
Residential excluding TOU	(353,125,724)	8.8508	$ (31,255)
Residential TOU	(6,881,609)	8.6959	$ (598)
Total Residential	(360,007,333)		$ (31,853)
SGS excluding Constant Load Rate	(114,604,459)	8.7576	$ (10,037)
SGS Constant Load Rate	(4,303,878)	6.3875	$ (275)
Total Small General Service	(118,908,337)		$ (10,311)
Medium General Service	(204,134,391)	8.5298	$ (17,412)
SGS Time of Use	(270,654,912)	6.6149	$ (17,903)
Seasonal and Intermittent Service	(10,432,909)	10.4174	$ (1,087)
Total Medium General Service	(485,222,212)		$ (36,403)
LGS excluding TOU and RTP	(9,975,804)	6.9033	$ (689)
LGS Time of Use	(13,716,731)	6.2761	$ (861)
LGS Real Time Pricing	(9,295,636)	5.0783	$ (472)
Total Large General Service	(32,988,171)		$ (2,022)
Sports Field Lighting	(77,824)	15.4594	$ (12)
Street Lighting	-	-	$ -
Traffic Signal Lighting	-	-	$ -
Total NC Retail	(997,203,877)		$ (80,601)

Note 1: Average customer class rates are based on annualized revenues, excluding revenues from basic customer charges, divided by per book sales.

Public Staff
Saillor Exhibit 1

Docket No. E-2, Sub 1219

Calculation of Weather Normalization Revenue Adjustment

(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	Revenue Adjustment[2] (d) = (b) × (c) ÷ 100,000
Residential	(626,372,114)	8.8115	$ (55,193)
Small General	(34,111,482)	8.7198	(2,974)
Medium General	(197,377,245)	7.0942	(14,002)
Large General	(327,342)	5.5487	(18)
Total NC Retail	(858,188,182)		$ (72,188)

Note 1: Average customer class rates are based on annualized revenues, excluding revenues from basic facilities charges, divided by per book sales.

Public Staff
Saillor Exhibit 2

Docket No. E-2, Sub 1219

Monthly NC Retail kWh Weather Adjustments updated through February 2020

North Carolina* Weather Adjustments

Month	Year	Residential	Small General	Medium General	Large General
Jan	2018	(277,937,135)	(6,626,328)	(31,754,911)	(11,498,345)
Feb	2018	221,876,986	493,106	2,606,684	-
Mar	2018	162,535,932	-	-	61,427,088
Apr	2018	(86,671,162)	-	-	(26,680,310)
May	2018	(23,581,120)	(1,094,181)	(7,003,255)	(12,269,037)
Jun	2018	(160,689,941)	(11,395,003)	(66,693,148)	(14,777,653)
Jul	2018	(81,084,028)	(4,847,525)	(26,876,906)	(76,175,964)
Aug	2018	21,370,452	1,538,541	8,556,495	4,443,838
Sep	2018	(111,660,208)	4,249,535	23,456,842	104,357,602
Oct	2018	(195,143,760)	(16,234,078)	(95,585,512)	(76,789,975)
Nov	2018	(6,790,109)	(17,483,369)	(105,757,837)	(41,675,647)
Dec	2018	(88,598,020)	17,287,821	101,674,304	89,311,060
Total		(626,372,114)	(34,111,482)	(197,377,245)	(327,342)

*Values were generated using the monthly historical ratio of NC actual billed sales to actual billed sales (NC/System)

Public Staff
Saillor Exhibit 3

Docket No. E-2, Sub 1219

Customer Growth and Change in Usage kWh Adjustments through February 29, 2020

Rate Class	Per Book kWh Sales	Test Year Number of Bills	Number of Bills at End of Period	Change in # of Bills[1]	Customer Growth kWh Adjustment	Change in Usage kWh Adjustment	Adjusted Per Book kWh Sales
Residential	16,666,046,589	14,562,331	14,964,900	402,569	455,313,658	(389,360,904)	16,731,999,343
Small General	1,982,596,401	2,006,644	2,037,876	31,232	29,696,159	(78,363,199)	1,933,929,361
Medium General	11,178,964,878	471,089	466,614	(4,475)	146,119,738	(296,808,924)	11,028,275,691
Large General	8,500,866,335	3,451	3,564	113	23,110,768	33,391,348	8,557,368,451
Street Lighting	85,107,971	2,318,787	2,364,384	45,597	1,677,242	-	86,785,213
Sports Field Lighting	1,134,908	946	1,020	74	80,635	28,533	1,244,076
Traffic Signal Lighting	4,754,792	63,311	61,932	(1,379)	(103,515)	-	4,651,277
Total NC Retail	38,419,471,874				655,894,685	(731,113,146)	38,344,253,412

Note 1: For the MGS and LGS customer classes, the change in the number of bills equals the number of bills added for new accounts minus the number of bills removed for closed accounts.

Public Staff
Saillor Exhibit 4

Docket No. E-2, Sub 1219

Calculation of Customer Growth Revenue Adjustment

(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	BFC Revenues[2] (d)	Revenue Adjustment (e) = (b) × (c) ÷ 100,000 + (d)
Residential excluding TOU	446,610,250	8.8508	$ 5,528	$ 45,057
Residential TOU	8,703,408	8.6959	$ 130	$ 886
Total Residential	455,313,658			$ 45,943
SGS excluding Constant Load Rate	28,621,309	10.8139		$ 3,095
SGS Constant Load Rate	1,074,850	11.1968		$ 120
Total Small General Service	29,696,159			$ 3,215
Medium General Service	61,472,997	8.7319		$ 5,368
SGS Time of Use	81,504,976	6.7230		$ 5,480
Seasonal and Intermittent Service	3,141,764	10.9476		$ 344
Total Medium General Service	146,119,738			$ 11,191
LGS excluding TOU and RTP	6,988,823	6.9225		$ 484
LGS Time of Use	9,609,632	6.2937		$ 605
LGS Real Time Pricing	6,512,313	5.0816		$ 331
Total Large General Service	23,110,768			$ 1,420
Sports Field Lighting	80,635	17.8052		$ 14
Street Lighting	1,677,242	30.8441		$ 517
Traffic Signal Lighting	(103,515)	9.1477		$ (9)
Total NC Retail	655,894,685			$ 62,292

Note 1: Average customer class rates are based on annualized revenues divided by per book sales.

Note 2: For Residential customers, revenues from Basic Facilities Charges are calculated separately.

Public Staff
Saillor Exhibit 5

Docket No. E-2, Sub 1219

Calculation of Change in Usage Revenue Adjustment

(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	Revenue Adjustment (d) = (b) × (c) ÷ 100,000
Residential excluding TOU	(381,918,196)	8.8508	$ (33,803)
Residential TOU	(7,442,708)	8.6959	$ (647)
Total Residential	(389,360,904)		$ (34,450)
SGS excluding Constant Load Rate	(75,526,849)	8.7576	$ (6,614)
SGS Constant Load Rate	(2,836,350)	6.3875	$ (181)
Total Small General Service	(78,363,199)		$ (6,795)
Medium General Service	(124,868,375)	8.5298	$ (10,651)
SGS Time of Use	(165,558,772)	6.6149	$ (10,952)
Seasonal and Intermittent Service	(6,381,778)	10.4174	$ (665)
Total Medium General Service	(296,808,924)		$ (22,267)
LGS excluding TOU and RTP	10,097,727	6.9033	$ 697
LGS Time of Use	13,884,375	6.2644	$ 870
LGS Real Time Pricing	9,409,246	5.0783	$ 478
Total Large General Service	33,391,348		$ 2,045
Sports Field Lighting	28,533	15.4594	$ 4
Street Lighting	-	30.8441	$ -
Traffic Signal Lighting	-	9.1477	$ -
Total NC Retail	(731,113,146)		$ (61,464)

Note 1: Average customer class rates are based on annualized revenues, excluding revenues from basic facilities charges, divided by per book sales.