SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-1:

Provide a copy of all documents identified in the Company Benefit Plan as detailed in Application Exhibit 1, page A-2. Provide a summary of the Customer Benefit Plan.

RESPONSE 7-1:

ORS Request 7-1 requests a summary of the "Customer Benefit Plan." SCE&G believes that ORS is requesting a summary of the "Company Benefit Plan." Assuming that SCE&G's interpretation is correct, attached to this response is a copy of SCANA's 2018 Benefits Summary which is provided to new employees.

As for the documents identified in the definition of Company Benefit Plan, enclosed is a compact disc containing the following plan documents labeled Response 7-1.

a) SCANA Corporation Health and Welfare Plan,
b) SCANA Corporation Retiree Welfare Benefits Plan,
c) SCANA Corporation Flexible Benefits Plan,
d) SCANA Corporation Healthcare Flexible Spending Account Plan,
e) SCANA Corporation Dependent Care Flexible Spending Account Plan,
f) SCANA Corporation Death Benefit Plan,
g) SCANA Corporation 401(k) Retirement Savings Plan, and
h) SCANA Corporation Retirement Plan.
i) SCANA Corporation 3-5-7 Employee Incentive Plan
j) SCANA Corporation Mid-Tier Annual Incentive Plan
k) SCANA Corporation Short-Term Annual Incentive Plan
l) SCANA Corporation Long-Term Equity Compensation Plan
m) SCANA Corporation Executive Deferred Compensation Plan
n) SCANA Energy Marketing Inc. Incentive Plan
o) SCANA Corporation Supplementary Key Executive Severance Benefits Plan
p) SCANA Corporation Supplementary Executive Plan

q) SCANA Corporation Supplemental Executive Retirement Plan
r) Paid Time Off Plans

Please note that there are other agreements between SCANA and its employees or former employees that contain confidential and sensitive information. Due to the confidential and sensitive nature of the information requested, SCE&G will make the information responsive to this request available to ORS for review and inspection at SCE&G's administrative offices after the execution of a confidentiality agreement.

RESPONSIBLE PERSON: Deborah Shurr

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
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DOCKET NO. 2017-207-E (8th Continuing AIR)
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REQUEST 7-2:

Provide a copy of the Company Disclosure Letter as identified in the Application Exhibit 1, page A-2.

RESPONSE 7-2:

The information responsive to this request contains confidential and sensitive information. Due to the confidential and sensitive nature of the information requested, SCE&G will make the information responsive to this request available to ORS for review and inspection at SCE&G's administrative offices after the execution of a confidentiality agreement

RESPONSIBLE PERSON: Chad Burgess

SOUTH CAROLINA ELECTRIC & GAS COMPANY
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REQUEST 7-3:

Provide a copy of the Director Compensation and Deferral Plan as identified in the Application Exhibit 1, page A-4.

RESPONSE 7-3:

Please see the document on the attached CD labeled Response 7-3.

RESPONSIBLE PERSON: Deborah Shurr

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
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REQUEST 7-4:

Provide a copy of the Parent Disclosure Letter as identified in the Application Exhibit 1, page A-6.

RESPONSE 7-4:

Due to the confidential and sensitive nature of the information requested, Dominion Energy will make the information responsive to this request available to ORS for review and inspection at the law offices of Nexsen Pruet, LLC after the execution of a confidentiality agreement.

RESPONSIBLE PERSON: Lisa S. Booth

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
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DOCKET NO. 2017-207-E (8th Continuing AIR)
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DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-5:

Provide a copy of the Parent Severance Program as identified in the Application Exhibit 1, page A-6.

RESPONSE 7-5:

See DE Attachments ORS 7-5(a) and (b).

RESPONSIBLE PERSON: Carmen Anderson

DOMINION RESOURCES, INC.

DOMINION SEVERANCE PROGRAM

(Amended and Restated Effective January 1, 2016)

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DOMINION RESOURCES, INC.

DOMINION SEVERANCE PROGRAM

SECTION 1

GENERAL

Section 1.1 **Purpose and Term.** Dominion Resources, Inc. has established the Dominion Severance Program (the "Plan"), originally effective as of January 27, 2000, as amended effective January 1, 2002, and as amended and restated March 1, 2006, July 1, 2007, January 1, 2012, and January 1, 2016. The Plan is intended to provide severance payments for Employees in the event of the involuntary termination of their employment under the circumstances described herein and will apply to Employees who are designated by the Plan Administrator as eligible for the Plan. With respect to Dominion Resources, Inc. and its subsidiaries as of the Effective Date, this Plan replaces all severance programs or policies maintained prior to the Effective Date.

Section 1.2 **Plan Administration.** The authority to control and manage the operation and administration of the Plan will be vested in a Plan Administrator, which will be Dominion Resources Services, Inc., or such person or committee as may be duly designated by Dominion Resources Services, Inc. The Plan Administrator will be the "named fiduciary" as described in Section 402 of ERISA, with respect to its authority under the Plan. The duties and responsibilities of the Plan Administrator are set forth in Section 5 of the Plan.

Section 1.3 **Source of Payments.** The obligations of the Company under the Plan are solely contractual. Any amount payable under the terms of the Plan will be paid from the general assets of the Company, and no trust or other separate fund will be established for this purpose. Other payments or benefits referenced under this Plan will be paid in accordance with the terms of those plans and are not payable under this Plan.

Section 1.4 **Notices.** Any notice or document required to be filed under the Plan will be considered to be properly filed if delivered or mailed via first class mail, postage prepaid, to the Manager – Employee Relations, Dominion Resources Services, Inc., One James River Plaza, 701 East Cary Street, Richmond, Virginia 23219. Any notice required under the Plan may be waived by the person entitled thereto.

Section 1.5 **Gender and Number.** Where the context admits, words in any gender will include any other gender, words in the singular will include the plural, and the plural will include the singular.

Section 1.6 **Plan Not Guarantee of Employment.** The Plan does not constitute a guarantee of employment by the Company, and eligibility for or participation in the Plan will not give any individual the right to be retained in the employ of the Company. The Company reserves all of its rights to discharge employees at will or to amend or modify any of the terms and conditions of their employment.

Section 1.7 **Covered Affiliates**. The Plan covers the Company and any Affiliate of the Company as of the Effective Date; provided, however, that any Affiliates so designated by the Company from time to time, as set forth on Schedule A attached hereto, shall be excluded from coverage under this Plan. The Employees of other entities that become Affiliates after the Effective Date will be covered by the Plan, except to the extent that the Company expressly excludes such Affiliate from participation in this Plan.

SECTION 2

DEFINITIONS

Section 2.1 **Actual Employment Termination Date** means the last day of a Participant's Advance Notice Period, or, if so designated by the Plan Administrator, the last day of a Participant's Special Leave to Retire.

Section 2.2 **Administrative Benefits Committee** means the committee appointed by the Board of Directors of Dominion Resources, Inc. or its authorized delegate.

Section 2.3 **Advance Notice Effective Date** means the first day of any month, or such other date designated by the Plan Administrator in writing as an Advance Notice Effective Date, as of which Advance Written Notice is given.

Section 2.4 **Advance Notice Period** means the period beginning on the Advance Notice Effective Date, regardless of the date such Advance Written Notice is actually received, and generally ending on the last day of the month following the month in which the Advance Notice Effective Date occurs.

Section 2.5 **Advance Written Notice** means the authorized written notification provided to an Employee by the Plan Administrator of his eligibility to participate in the Plan, which is designated by the Plan Administrator as an Advance Written Notice.

Section 2.6 **Affiliate** means (i) any corporation other than the Company that is either a subsidiary corporation or an affiliated or associated corporation of the Company which together with the Company is a member of a "controlled group" of corporations, (ii) any organization which together with the Company is under "common control," or (iii) any organization which together with the Company is an "affiliated service group," as those terms are defined in Sections 414(b), 414(c) and 414(m) of the Code.

Section 2.7 **Alternate Medical Continuation Coverage** means the benefit described in section 4.4(B) of this Plan.

Section 2.8 **Buyer** means either (i) the entity acquiring the assets or operations of any corporate Affiliate of the Company, business unit, department, function, or functional group in which one or more Employees are employed, through asset sale, stock sale, or change in control; (ii) the entity assuming operations of any corporate Affiliate of the Company, business unit, department, function, or functional group in which one or more Employees are employed in a transaction that establishes a contractual relationship between the Company and the Buyer for the provision of the target services; (iii) a successor operator to whom the Company transfers or assigns an operations & maintenance or similar agreement entered into between the Company and any other entity; or (iv) a replacement operator that enters into an operations & maintenance or similar agreement with any other entity immediately following the expiration or termination of the Company's operations & maintenance or similar agreement with that same other entity.

Section 2.9 **Claimant** means an individual who submits a claim to the Plan Administrator seeking to obtain benefits, a different amount of benefits, or other rights under the Plan.

Section 2.10 **COBRA** means the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended at any relevant time.

Section 2.11 **Code** means the Internal Revenue Code of 1986, as amended at any relevant time.

Section 2.12 **Company** means Dominion Resources, Inc. and/or any Affiliate, as defined herein.

Section 2.13 **Demotion** means a position that the Company offers to an Employee (when the number of individuals in such Employee's current position is or will be reduced or such Employee's current position is or will be eliminated) that either (i) is a different position that has a market reference value that is 10% or more below the market reference value of his current position; or (ii) is, in the judgment of the Plan Administrator, a position for which the scope of responsibilities and duties is significantly reduced as compared to his current position. The term "Demotion" does not apply to a position that a Buyer offers to an Employee in a Divestiture or an Outsourcing.

Section 2.14 **Divestiture** means the disposition by the Company to a Buyer of any corporate Affiliate of the Company or a business unit, department, function, or functional group in which one or more Employees are employed, through asset sale, stock sale, or change in control. The term "Divestiture" shall also include the transfer, assignment, expiration or termination of an operations & maintenance or similar agreement previously entered into between the Company and any other entity under which one or more Employees are employed.

Section 2.15 **Effective Date** means January 1, 2016 with respect to this amended and restated Plan. The original effective date of the Plan was January 27, 2000, and the Plan was also amended effective January 1, 2002, March 1, 2006, July 1, 2007, and January 1, 2012.

Section 2.16 **Employee** means any individual who is (i) classified by the Company as a regular full-time employee or as a Part-Time Employee and (ii) paid through the Company's regular United States payroll. The term "Employee" does not include any person classified by the Company as an independent contractor or a leased employee (regardless of whether such classification is determined to be correct as a matter of law). An individual who is a member of a collective bargaining unit is not an Employee unless, for purposes of compliance with Labor Management Relations Act, inclusion in this Plan is allowed pursuant to the terms of a collective bargaining agreement in existence or entered into in the future as a result of good-faith bargaining between the employee representatives and the Company wherein the employee representatives elect coverage under the Plan and the Company consents. All employees whose assigned work location is outside the United States will be excluded from coverage regardless of which Company payroll covers such employees. Further, all executives of the Company or employees who have an individual employment contract or other agreement with the Company that provides for the payment of severance benefits after termination of employment, including, without limitation, a salary continuation or incentive agreement, will not be considered an "Employee" for purposes of this Plan, unless the executive's or employee's employment contract or other agreement explicitly requires his participation in the Plan.

Section 2.17 **ERISA** means the Employee Retirement Income Security Act of 1974, as amended at any relevant time.

Section 2.18 **General Release of Claims or Release** means a release, in a form satisfactory to the Company and the Plan Administrator, that waives all claims that the Participant has or may have against the Company or any Affiliate, including claims for other severance benefits or compensation, other employee benefits under plans or programs provided by the Company, workforce reduction or exit incentive programs now in effect or implemented in the future by the Company, and any other claims that the Participant has or may have that may be legally waived in connection with the Participant's employment and termination of employment. The Release may also require the Participant to maintain the confidentiality of any information that is considered by the Company to be a trade secret, confidential, or proprietary to the Company.

Section 2.19 **Outsourcing** means the assumption by a Buyer of the operations of a business unit, department, function, or functional group of the Company in which one or more Employees are employed, in a transaction that establishes a contractual relationship between the Company and the Buyer for provision of the target services.

Section 2.20 **Participant** means an Employee who has satisfied the eligibility requirements provided in Section 3 of the Plan.

Section 2.21 **Part-Time Employee** means an Employee who is not employed on a full-time basis with the Company but who is scheduled to work 1,000 or more hours for the Company in a calendar year.

Section 2.22 **Preference Form** means the form provided by the Company to designated Employees (so designated by the Company or a business unit of the Company) whose position may be affected by reductions or job eliminations due to merger, reorganization, restructuring, or process change. The form is intended to allow such Employees to express their preference to receive severance benefits instead of a reassignment of position under varying circumstances, which preference is not binding on the Company.

Section 2.23 **Plan** means the Dominion Severance Program, as set forth in this document.

Section 2.24 **Plan Administrator** means Dominion Resources Services, Inc.

Section 2.25 **Plan Year** means the calendar year.

Section 2.26 **Qualifying Offer of Employment** means an offer of employment from a Buyer in the case of an Outsourcing: (i) that is at a base salary for the first year following the Outsourcing equal to or greater than ninety percent (90%) of the Employee's base salary from the Company immediately before the effective date of the Outsourcing; (ii) that does not require relocation (as that term is defined by the Company's relocation/transfer policy) by the Employee at the time of the offer; (iii) that provides immediate eligibility under the Buyer's active employees' medical benefits plan, whether or not that medical benefits plan provides benefits comparable to benefits provided under the Company's plans; (iv) that provides some form of paid time off for vacation and illness and provides for participation in a retirement plan qualified under the Internal Revenue Code; and (v) that provides if the Employee is terminated within one year of the Outsourcing through no fault of the Employee, the Employee will be eligible for severance benefits under Buyer's program, plan or policy (which may be subject to conditions, including but not limited to execution of a release) that recognizes the Employee's prior service with the Company. The definition of a Qualifying Offer of Employment applies only in the context of an Outsourcing and not in the context of a Divestiture.

Section 2.27 **Retiree Medical Plan** means the Dominion Retiree Health and Welfare Plan or any successor to this plan, as it may be amended from time to time.

Section 2.28 **Retirement Plan** means the Dominion Pension Plan or any successor to this plan, as it may be amended from time to time.

Section 2.29 **Scheduled Employment Termination Date** means a Participant's original employment termination date as set forth in his Advance Written Notice and normally described therein as his "Scheduled Employment Termination Date," which is generally the last day of his two-month Advance Notice Period.

Section 2.30 **Severance Payment** means the amount of severance payments a Participant is entitled to receive under this Plan in accordance with Section 4.2, upon satisfying the requirements set forth under Section 3.1 and Section 3.5.

Section 2.31 **Special Employment Termination Date** means the last day of the month in which a Special Retiree satisfies both the age and service requirements for early retirement under the Retirement Plan. However, in the event that a Special Retiree has previously satisfied the years of service requirement for early retirement and then first satisfies the age requirement for early retirement on the first day of a month, his Special Employment Termination Date is the last day of the previous month.

Section 2.32 **Special Leave to Retire** means a Company-approved special paid leave beginning with the day after the Special Retiree's Scheduled Employment Termination Date and ending on his Special Employment Termination Date, in accordance with the provisions of Section 3.3. Special Leave to Retire is available only to a participant in the Traditional Pension benefit of the Retirement Plan, and not to a participant in the Cash Balance benefit of the Retirement Plan.

Section 2.33 **Special Retiree** means a Participant who qualifies for, elects, and goes on Special Leave to Retire to reach eligibility for early retirement under the Traditional Pension benefit of the Retirement Plan, in accordance with the provisions of Section 3.3.

Section 2.34 **Weekly Base Pay** means a Participant's regular base pay per week for payroll purposes in effect on the Participant's Advance Notice Effective Date. For the purpose of calculating the amount of Severance Payments under Section 4.2, the term Weekly Base Pay does not include overtime, incentive pay, or bonuses or supplemental payments, including but not limited to any geographical supplement or parking supplement.

SECTION 3

ELIGIBILITY AND PARTICIPATION

Section 3.1 **Eligibility for the Dominion Severance Program**. An Employee will become a Participant in the Plan in accordance with the following terms and conditions:

A. An Employee will be eligible to participate in the Plan when (i) the Plan Administrator has selected the Employee to participate in the Plan and provided him an Advance Written Notice; (ii) the number of individuals in such Employee's position is or will be reduced or such Employee's position is or will be eliminated; (iii) the Employee has executed the applicable General Release of Claims in accordance with Section 3.5 and the revocation period has elapsed without the Employee's having revoked the Release; and (iv) only if such employee (1) is not offered a new position with the Company; (2) is offered a new position with the Company, but the new position would require relocation of his household (as defined under the Company's relocation reimbursement policy), the employee rejects such offer of employment, and his employment with the Company is terminated; or (3) is offered a position with the Company that the Plan Administrator considers a Demotion and the employee rejects such offer, and his employment with the Company is terminated. An Employee will not become eligible to participate in the Plan if, when such Employee's position is eliminated, the Company offers him a new position with the Company that would not require relocation of his household and that the Plan Administrator does not consider a Demotion, regardless of whether the Employee accepts the position. An Employee may become eligible to receive Severance Payments and other benefits under this Plan notwithstanding the fact that he is eligible to retire or has retired from the Company, provided such employee otherwise satisfies the eligibility requirements of this Section 3.1.

B. The Company (or a business unit of the Company), in its sole discretion, will make decisions regarding the staffing needs and employment levels as a part of its business function and in accordance with the Company's plans relating to merger, reorganization, restructuring, Outsourcing, Divestiture, process change, or other management goals. Actions taken by the Company (or a business unit of the Company) in making these business decisions regarding staffing, reassignment, and job elimination will not be construed as actions of the Plan Administrator acting in its capacity as fiduciary under this Plan. The Plan Administrator, in its sole discretion, will determine whether and when an Employee is eligible for receipt of an Advance Written Notice.

C. Certain Employees may complete a Preference Form in conjunction with the Company's process of reducing or eliminating jobs. The information provided by any Employee on his completed Preference Form will be one of many factors that may be considered by the Company in making its decisions regarding the staffing needs. Submission of a Preference Form by an Employee is not a guarantee that the Employee will receive an Advance Written Notice, or if eligible for the Plan, that the Employee will be eligible on any specific date. The completion of a Preference Form by an Employee does not affect the Plan Administrator's complete discretion to determine whether and/or when to select the Employee to participate in the Plan.

D. Notwithstanding the foregoing,

1. In the event that jobs are eliminated as a result of an Outsourcing event, an Employee will not be eligible for participation in this Plan if the Employee receives a Qualifying Offer of Employment from the Buyer in connection with the Outsourcing event, regardless of whether the Employee accepts the Qualifying Offer of Employment. The Plan Administrator may, in its sole discretion, determine whether an Employee who does not receive a Qualifying Offer of Employment with a Buyer in connection with an Outsourcing will be eligible to participate in this Plan and receive an Advance Written Notice.

2. In the event that jobs are eliminated as a result of a Divestiture, an Employee will not be eligible to participate in this Plan if the Employee continues employment with the Buyer or receives an offer of employment from the Buyer, regardless of whether the offer would constitute a Qualifying Offer of Employment if made in the event of an Outsourcing and regardless of whether such Employee accepts employment with the Buyer. This provision is intended to apply to any Employee whose job is eliminated as a direct result of a Divestiture. An Employee whose position is eliminated as a direct result of a Divestiture and who is not offered employment by the Buyer may be selected by the Plan Administrator to participate in the Plan and receive an Advance Written Notice.

Section 3.2 **<u>Advance Notice Period</u>.** During the Advance Notice Period, Participants will be expected to complete any pending work assignments, perform other work-related duties as requested by supervisory personnel, and otherwise remain an employee in good standing of the Company. An Employee designated to participate in the Plan and in receipt of an Advance Written Notice in accord with Section 3.1(A) (i) or 3.1(D) who voluntarily terminates his employment prior to the end of the Advance Notice Period or who otherwise does not remain an employee in good standing throughout the Advance Notice Period will not receive the benefits described under this Plan.

Section 3.3 **<u>Special Leave to Retire</u>.** A Participant who is a participant in the Traditional Pension benefit of the Retirement Plan and who, as of his Scheduled Employment Termination Date, is not eligible to retire under the terms and conditions of the Retirement Plan, but who, during the time when Severance Payments are to be paid under Section 4.3 of the Plan, will attain the earliest date such Participant is able to retire under the Retirement Plan, may make a one-time, written election to be placed on a Special Leave to Retire (thereby becoming a "Special Retiree").

A. Severance Payments will be paid as salary continuation payments during the period of the Special Leave to Retire. For purposes of this Section 3.3, such payments will be considered as wages or compensation for the purpose of participation in and employee contributions to any applicable employee benefit plans in which the Special Retiree is participating as of his Scheduled Employment Termination Date; <u>provided,</u>

however, that a Special Retiree's active participation, if any, in the Dominion Salaried Savings Plan will end on his Scheduled Employment Termination Date, and neither he nor the Company may make contributions to that plan during his Special Leave to Retire. Notwithstanding the foregoing, salary continuation payments paid during the Special Leave to Retire will be part of the Severance Payments due to the Special Retiree under the Plan. The period of Special Leave to Retire shall not be considered as service for purposes of determining the amount of Severance Payments to which the Special Retiree may be entitled under Section 4.2 of the Plan.

B. If the Special Retiree exhausts the Severance Payments after satisfying the age and service requirements for early retirement under the Retirement Plan but before reaching his Special Employment Termination Date, the remainder of the Special Leave to Retire will be unpaid. If the Special Retiree has not exhausted the Severance Payments as of the Special Employment Termination Date, he will receive the balance of Severance Payments as provided in Section 4.3 of the Plan.

C. The written election for Special Leave to Retire described in this Section 3.3 must be submitted to the person designated in the Participant's Advance Written Notice prior to the Participant's Scheduled Employment Termination Date and must be accompanied by an executed General Release of Claims in a form acceptable to the Company and the Plan Administrator. A Special Retiree must remain an employee in good standing throughout the Special Leave to Retire period to receive the benefits described under this Plan.

Section 3.4 Reemployment. Employees may apply for open positions with the Company at any time. Any Participant who is offered and accepts a position will cease to be a Participant under this Plan as of his reemployment date and will not be entitled to further benefits under this Plan after that date.

Section 3.5 General Release of Claims. To be eligible for a Severance Payment and certain other benefits under the Plan, each Participant must sign and not revoke a General Release of Claims in a form satisfactory to the Company and the Plan Administrator. Any Participant who signs a Release and later revokes such Release (in accordance with its terms and applicable law) will cease to be a Participant under the Plan. The General Release of Claims will affect a Participant's rights when it becomes effective, and each Participant will be advised to consult an attorney at his own expense prior to executing the General Release of Claims. Unless otherwise determined by the Plan Administrator, the General Release of Claims will give each Participant at least forty-five (45) days to consider whether to sign it, and each Participant will have seven (7) days to revoke the General Release of Claims after it is signed. If an employee who has received an Advance Written Notice does not sign and submit the General Release of Claims within the time specified in the Advance Written Notice, his employment nonetheless will end on his Scheduled Employment Termination Date.

SECTION 4

SEVERANCE PAYMENTS

Section 4.1 **Entitlement to Severance Payments**. Subject to the terms and conditions of the Plan, the Plan Administrator may, in its sole discretion, grant a Severance Payment or other benefits under this Plan to a Participant in an amount determined in accordance with the provisions of the Plan. Participants who receive a Severance Payment under this Plan will not be entitled to receive severance benefits or severance payments under any other plan or program of the Company or an Affiliate. Further, an Employee who receives severance benefits or severance payments during the term of this Plan from any other severance program, plan or arrangement maintained by the Company or an Affiliate will not be entitled to receive benefits from this Plan.

Section 4.2 **Amount of Severance Payment**. Subject to the terms and conditions of the Plan, a Participant who is entitled to a Severance Payment under the Plan will be entitled to an amount determined in accordance with one of the following formulas as either a regular full-time Employee or a regular Part-Time Employee:

A. Regular Full-Time Employee: Each Participant who is a regular, full-time Employee on his Advance Notice Effective Date will receive a Severance Payment in an amount equal to three times his Weekly Base Pay times the number of years of service that the Participant has with the Company (or any predecessor company recognized in calculating the employment service date). A Participant's years of service for purposes of this Plan will be determined as each full year of service, and each partial year of six (6) or more months will count as a full year. Service for purposes of this Plan will be calculated based on the period beginning with a Participant's hire date (or, if applicable, such Participant's "employment service date," as that term is defined under applicable Company administrative procedures relating to calculating an Employee's service for purposes other than service crediting under the Retirement Plan) and ending on his Scheduled Employment Termination Date. If a Participant has been rehired by the Company after receiving benefits from this Plan, the Participant's service at his subsequent Scheduled Employment Termination Date will be calculated based on the Participant's most recent hire date, not his employment service date.

B. Regular Part-Time Employee: Each Participant who is a regular Part-Time Employee on the Advance Notice Effective Date will be entitled to receive a Severance Payment calculated in accordance with subsection 4.2(A), where years of service will be equal to the sum of (i) and (ii), as follows: (i) the number of years (including any partial year) in which the Participant has served in part-time status immediately before the Advance Notice Effective Date, divided by two; and (ii) the number of years (if any) in which the Participant served in qualifying full-time status with the Company or a participating Affiliate.

C. Minimum and Maximum Severance Payments: Each Participant will receive a minimum Severance Payment of nine (9) times his Weekly Base Pay. The maximum Severance Payment available under the Plan is fifty-two (52) times the Participant's Weekly Base Pay.

D. Coordination with Deferred Compensation Rules: The Plan is intended to be a welfare benefit plan governed by ERISA that provides for severance benefits to designated employees in the event of involuntary termination of employment from the Company. The Plan is intended to be a "separation pay plan" within the meaning of Treasury Regulation Section 1.409-1(9)(iii) that does not provide for the deferral of compensation under Code Section 409A. Accordingly, in no event shall the Severance Payments payable to a Participant under this Plan exceed two times the lesser of (i) the Employee's annual rate of pay for the calendar year preceding the calendar year in which the termination of employment occurs, or (ii) the maximum amount that may be taken into account under a qualified plan pursuant to Code Section 401(a)(17) for the calendar year in which the termination of employment occurs. In addition, all Severance Payments to which a Participant is entitled under this Plan shall be paid no later than December 31 of the second calendar year following the calendar year in which the Participant terminates employment.

Section 4.3 Form and Timing of Severance Payments. Severance Payments will be payable in installments according to the normal payroll payment schedules currently in effect for each Participant. Severance Payments will begin with the first payroll period immediately following the Participant's Scheduled Employment Termination Date. For a Special Retiree, Severance Payments will be paid as salary continuation payments during the period of the Special Leave to Retire.

Section 4.4 Coordination With Other Benefits. Except for Special Retirees, a Participant receiving Severance Payments under this Plan will cease to be considered an employee of the Company for purposes of eligibility and participation in other benefit plans sponsored by the Company as of his Scheduled Employment Termination Date. Except as otherwise described in this Section 4.4, the terms of the other benefit plans shall determine a Participant's treatment under such plans following his Scheduled Employment Termination Date. Except as provided in subsection (D) below, each Participant who has signed and not revoked the applicable General Release of Claims under Section 3.5 will be entitled to the following benefits:

A. Medical Coverage. The provisions of this section A apply to all Participants except Special Retirees.

1. If a Participant has signed the applicable General Release of Claims and timely elected COBRA coverage in accordance with the terms of the Company's medical plan, the Company will pay for up to six (6) months of the cost of COBRA coverage for such Participant, based on the level of coverage in effect as of the Participant's Scheduled Employment Termination Date. The COBRA coverage period will begin on the first of the month following the Participant's Scheduled Employment Termination Date.

2. If a Participant has signed the General Release of Claims and has timely elected to commence receiving benefits under the Retiree Medical Plan on the first of the month following the Participant's Scheduled Employment Termination Date, then in lieu of paying the cost of COBRA coverage as described in subsection 1, the Company will pay up to six (6) months of retiree contributions under the Retiree Medical Plan.

3. A Participant who, during the time when Severance Payments are to be paid under Section 4.3 of the Plan, will attain age 58 with at least 10 years of pension service (and who satisfies the other requirements for coverage) will be eligible to participate in retiree medical coverage under the Retiree Medical Plan on the first of the month following the Participant's Scheduled Employment Termination Date, and subparagraph 2 of this section will apply.

B. Alternate Medical Continuation Coverage. A Participant may elect Alternate Medical Continuation Coverage for up to 36 months, beginning the first day of the month following his or her Actual Employment Termination Date, if the Participant (1) is at least 50 years old with at least 20 of years of service on the last day of the calendar year in which his or her Actual Employment Termination Date occurs and (2) is not ineligible under subparagraph 2 of this section. For purposes of determining eligibility for Alternate Medical Continuation Coverage, years of service will be calculated in accordance with Section 4.2(A) of this Plan, provided that additional service will be imputed for the period between the Actual Employment Termination Date and the end of the calendar year in which the Actual Employment Termination Date occurs.

1. Participants in Alternate Medical Continuation Coverage will receive Option C medical coverage. The Company will pay the cost of this coverage for the first six months, and for the remaining 30 months, the Participant will pay the same monthly rates paid for Option C medical coverage by active non-union employees who are receiving the wellness premium credit.

2. Alternate Medical Continuation Coverage is not available to Participants who are eligible to elect the Company's traditional retiree medical coverage, or to Participants who are eligible to participate in the Company's retiree medical account ("RMA") program. In addition, after the first six months of Alternate Medical Continuation Coverage, Alternate Medical Continuation Coverage is no longer available to a Participant who is eligible to enroll in a medical plan sponsored by another employer, including the Participant's spouse's employer. A Participant who becomes eligible to enroll in a medical plan sponsored by another employer (including a spouse's employer) while participating in Alternate Medical Continuation Coverage must report the availability of such other employer coverage to the Plan Administrator within 30 days of becoming eligible for the other employer coverage, and the Participant's eligibility for Alternate Medical Continuation Coverage will cease as of the first date on which the Participant could have been covered under the other employer coverage. If the Participant does not so report the availability of other employer coverage, the Participant may be responsible for claims paid under Alternate

Medical Continuation Coverage on behalf of the Participant (or the Participant's spouse or dependents) after the Participant became ineligible pursuant to this paragraph. Participants may be required to periodically verify that they are ineligible to enroll in a medical plan sponsored by another employer, including a spouse's employer.

3. Under Alternate Medical Continuation Coverage, a Participant may elect dependent coverage for any person who was the Participant's spouse or dependent as of the Participant's Actual Employment Termination Date, but only if the Participant enrolls that person at the same time that the Participant initially enrolls in Alternate Medical Continuation Coverage.

C. Life Insurance. The provisions of this section C apply to all Participants except Special Retirees. Each Participant will receive a continuation of his employee-only life insurance at the level in effect on his Scheduled Employment Termination Date. The Company will pay the first six months of premiums for this insurance coverage, beginning with the first premium due after his Scheduled Employment Termination Date. To the extent that a Participant's life insurance exceeds $50,000, the Participant may have imputed income relating to the excess amount over $50,000.

D. Outplacement Services. Any Employee who receives an Advance Written Notice will be eligible for outplacement services, which will be provided at the Company's expense through an independent firm under contract with the Company. Outplacement services must be started within six months from the Employee's Advance Notice Effective Date. An Employee does not have to satisfy section 3.5 to be eligible to receive the outplacement services described in this subsection 4.4(D).

E. Cash Balance Pension. A Participant who is a participant in the Cash Balance formula of the Retirement Plan will be vested in his accrued benefit under that plan at the end of his Advance Notice Period, regardless of his years of service.

F. Other Benefits. The Plan Administrator may, in its sole discretion, offer other benefits (including types or levels of benefits not listed in this Plan document) to Employees who become eligible to participate in the Plan. The terms and conditions of other benefits that may be offered will be described in the Advance Written Notice or the Summary Plan Description provided to the Employee.

Section 4.5 Nonalienation. Participants will not have any right to pledge, hypothecate, anticipate, or in any way create a lien upon any benefits provided under this Plan, and no benefits payable hereunder will be assignable in anticipation of payment, either by voluntary or involuntary acts, or by operation of law. Nothing in this Section 4.5 will limit a Participant's rights or powers to dispose of his property by will, limit any rights or powers which his executor or administrator would otherwise have with regard to benefits to which a Participant is entitled hereunder, or restrict any right of set-off, counterclaim, or recoupment which the Company may otherwise have against any Participant.

Section 4.6 **Withholding.** All payments with respect to a Participant under this Plan will be subject to applicable withholding of federal, state, and local taxes and other applicable deductions. Notwithstanding the foregoing, payments made under this Plan after a Participant's Actual Employment Termination Date will not be considered "Earnings" as that term is used with respect to salary deferral arrangements, including, without limitation, the Dominion Salaried Savings Plan.

Section 4.7 **Benefits on Death.** In the event of the death of a Participant after becoming entitled to a Severance Payment under the Plan but before complete payment of his benefits hereunder, any unpaid Severance Payments will be paid to his estate in a lump sum payment.

SECTION 5

PLAN ADMINISTRATOR

Section 5.1 **Duties and Authority of Plan Administrator**. Except as otherwise specifically provided in this Section 5, in controlling and managing the operation and administration of the Plan, the Plan Administrator will have the following discretionary authority, powers, rights, and duties in addition to those vested in it elsewhere in the Plan:

A. to enforce the Plan in accordance with its terms and with such applicable rules of procedure and regulations as may be adopted by the Plan Administrator;

B. to determine conclusively all questions arising under the Plan, including the power to determine the eligibility of employees or Claimants and the rights of Participants or Claimants to benefits under the Plan, to interpret and construe the provisions of the Plan, and to remedy any ambiguities, inconsistencies, or omissions of whatever kind;

C. to employ or utilize agents, attorneys, accountants, or other persons (who may also be employed by or represent the Company) for such purposes as the Plan Administrator considers necessary or desirable to discharge its duties; and

D. to establish a claim procedure in accordance with Section 503 of ERISA.

Section 5.2 **Plan Administrator Decision Final.** To the extent permitted by law, any interpretation of the Plan and any decision on any matter within the discretion of the Plan Administrator made by it in good faith will be binding on all persons. A misstatement or other mistake of fact will be corrected when it becomes known, and the Plan Administrator will make such adjustment on account thereof as it considers equitable and practicable.

Section 5.3 **Exercise of Plan Administrator Duties**. In exercising its authority under the Plan, the Plan Administrator may delegate all or any part of its responsibilities and powers to any one or more of the committees of the Company and may delegate all or any part of its responsibilities and powers to any person or persons selected by it, including designated officers or employees of the Company.

SECTION 6

CLAIMS PROCEDURES

Section 6.1 **Explanation of Benefits**. Although a Participant does have to sign, submit and not revoke a General Release of Claims, as described in Section 3.5, a Participant does not have to file a claim in order to receive Severance Payments and other related benefits under this Plan. Any Claimant who has questions about the Plan, including questions about his eligibility for benefits, the amount of his Severance Payment, how benefits are calculated, or other issues relating to Plan interpretation is encouraged to submit such questions in writing to the Plan Administrator. The Plan Administrator will provide a written response to all such inquiries. If a Claimant believes, after reviewing the Plan Administrator's explanation of benefits, that he is eligible for benefits under this Plan or that the Severance Payments to which he is entitled under the Plan have been calculated incorrectly, the Participant may submit a written claim for Plan benefits in accordance with Section 6.2 of this Plan.

Section 6.2 **Claims for Benefits**. A Claimant may submit a written claim for benefits under the Plan in accordance with the terms and conditions set forth in this Section 6.2.

A. Filing of Claims. A claim for benefits shall be made by filing a written request with the Plan Administrator, which shall be delivered to the Plan Administrator and accompanied by such substantiation of the claim as the Plan Administrator considers necessary and reasonable for the type of claim being filed.

B. Denial of Claims. If a claim is denied in whole or in part, the Claimant shall receive a written or electronic notice explaining the denial of the claim within ninety (90) days after the Plan Administrator's receipt of the claim, unless special circumstances exist that require an extension of the time for processing such claim. If an extension of time is necessary, the Claimant shall be notified in writing of the extension and reason for the extension within ninety (90) days after the Plan Administrator's receipt of the claim. The written extension notification shall also indicate the date by which the Plan Administrator expects to render a final decision. A notice of denial of claim shall contain the following:

1. the specific reason or reasons for the denial;

2. reference to the specific Plan provisions on which the denial is based;

3. a description of any additional materials or information necessary for such Claimant to perfect the claim and an explanation of why such material or information is necessary; and

4. a description of the Plan's review procedures and the time limits applicable to such procedures, including a statement of the Claimant's right to

bring a civil action under Section 502(a) of ERISA following an adverse benefit determination on review.

C. Payment of Claims. The full value of a payment made according to the provisions of the Plan satisfies that much of the claim and all related claims under the Plan against the Plan Administrator and the Company, each of whom, as a condition to a payment from it or directed by it, may require the Participant, beneficiary, or legal representative to execute a receipt and release of the claim in a form determined by the person requesting the receipt and release.

Section 6.3 Review of Claims. A Claimant whose claim for benefits has been denied by the Plan Administrator may request a review of such denial in accordance with the terms and conditions of this Section 6.3.

A. Request for Review of Denied Claims. A Claimant may file a written request for a review of the denial of a claim within sixty (60) days after receiving written notice of the denial. The written request should be sent to the Plan Administrator, who will forward it to the Administrative Benefits Committee for review. The Claimant may submit written comments, documents, records, and other relevant information in support of the claim. A Claimant shall be provided, upon request to the Plan Administrator and without charge, reasonable access to, and copies of, all documents, records, and other information relevant to the Claimant's claim for benefits. A document, record, or other information shall be considered relevant if it:

1. was relied upon in denying the claim;

2. was submitted, considered, or generated in the course of processing the claim, regardless of whether it was relied upon;

3. demonstrates compliance with the claims procedures process; or

4. constitutes a statement of Plan policy or guidance concerning the denied benefit, regardless of whether it was relied upon.

Relevant information shall not include any documents or records (or portions thereof) that would, through their release, violate any other applicable law or compromise the confidentiality of certain employee data or business records, including, but not limited to, any documents subject to attorney-client privilege.

B. Review Procedures. In reviewing a denied claim, the Administrative Benefits Committee shall take into consideration all comments, documents, records, and other information submitted by the Claimant in support of the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

C. Decisions on Reviewed Claims. The Administrative Benefits Committee will notify the Claimant in writing of its decision on the appeal. Such notification will be in writing in a form designed to be understood by the Claimant. If the claim is denied in whole or in part on appeal, the notification will also contain:

1. the specific reason or reasons for the denial;

2. reference to the specific Plan provisions on which the determination is based;

3. a statement that the Claimant is entitled to receive, upon request to the Plan Administrator and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the Claimant's claim for benefits. A document, record, or other information shall be considered relevant if it:

(a) was relied upon in denying the claim;

(b) was submitted, considered, or generated in the course of processing the claim, regardless of whether it was relied upon;

(c) demonstrates compliance with the claims procedures process; or

(d) constitutes a statement of Plan policy or guidance concerning the denied benefit, regardless of whether it was relied upon; and

4. a statement that the claimant has a right to bring an action under Section 502(a) of ERISA.

Relevant information shall not include any documents or records (or portions thereof) that would, through their release, violate any other applicable law or compromise the confidentiality of certain employee data or business records, including, but not limited to, any documents subject to attorney-client privilege.

Such notification will be given by the Administrative Benefits Committee within sixty (60) days after the complete appeal is received by the Administrative Benefits Committee (or within one hundred twenty (120) days if the Administrative Benefits Committee determines special circumstances require an extension of time for considering the appeal, and if written notice of such extension and circumstances is given to the Claimant within the initial sixty (60) day period). Such written extension notice shall also indicate the date by which the Administrative Benefits Committee expects to render a decision.

If the Claimant's written request for review is received by the Plan Administrator more than thirty (30) days before an Administrative Benefits Committee meeting, the Administrative Benefits Committee's decision must be rendered at the next meeting after the request for review is received. If special circumstances require an extension of time for processing, the Administrative Benefits Committee's decision must be rendered not later than the Administrative Benefits Committee's third meeting after the request for review is received, and written notice of the extension must be furnished to the Claimant before the extension begins. In the case of such regularly scheduled meetings, the Claimant shall be notified of the review determination as soon as possible, but no later than five days after the review determination has been made. If notice that a claim has been denied on review is not received by the Claimant within the time required in this paragraph, the claim is deemed denied on review.

Section 6.4 **<u>Compliance With Regulations</u>**. Notwithstanding anything in this Section 6 to the contrary, the Plan Administrator and the Administrative Benefits Committee shall make all determinations regarding claims for benefits of Participants or Claimants in accordance with Section 2560.503-1 of the Department of Labor Regulations.

Section 6.5 **<u>Claims for Benefits Under Other Plans</u>**. Claims for benefits under any of the other plans described in Section 4.4, including claims for eligibility or participation in such other plan or plans based upon participation in this Plan, shall be made pursuant to the claims procedures of such other plans.

SECTION 7

AMENDMENT OR TERMINATION

Section 7.1 **Amendment and Termination**. The Company may, by action of its Board of Directors or an authorized delegate thereof, amend or terminate this Plan at any time, to take effect retroactively or otherwise; provided, however, that no amendment or termination will adversely affect the Severance Payments, if any, payable under this Plan with respect to Participants whose employment with the Company terminated prior to such amendment or termination of the Plan, unless otherwise required under applicable law.

Section 7.2 **Successors**. The obligations and rights of the Company under the Plan will be binding upon, and inure to the benefit of, any assignee or successor in interest to the Company (whether direct or indirect, by purchase, merger, consolidation, or otherwise). Subject to the provisions of Section 7.1, the Company will not merge or consolidate with any other corporation, or liquidate or dissolve without making suitable arrangements for the payment of any benefits which are then payable under the Plan.

* * * * *

IN WITNESS WHEREOF, the Company has caused this Plan to be executed this 30 day of June, 2016.

DOMINION RESOURCES SERVICES, INC.

By: ______________________

Wendy T. Wellener
Vice President – Human Resources

SCHEDULE A

Affiliates Excluded from Coverage

Dominion Capital, Inc. and its subsidiaries (Effective as of January 27, 2000)

Dominion Energy Canada Limited

FIRST AMENDMENT
TO THE DOMINION SEVERANCE PROGRAM
(Amended and Restated Effective January 1, 2016)

DOMINION RESOURCES, INC. (the "Company") sponsors the Dominion Severance Program, amended and restated effective January 1, 2016. Section 7.1 of the Plan authorizes the Board of Directors of the Company (the "Board") or an authorized delegate of the Board to amend the Plan at any time. Accordingly, the Company hereby amends the Plan in accordance with the powers granted under Section 7.1 of the Plan. This amendment shall supersede the provisions of the Plan to the extent those provisions are inconsistent with the provisions of this amendment.

NOW, THEREFORE, the Plan is amended as follows:

1. Effective [**September 1, 2016**], Section 4.4(B)(2) is amended by adding the following sentence to the beginning thereof:

> "Alternate Medical Continuation Coverage is available only to Participants who would otherwise have been eligible for retiree medical coverage under the Retiree Medical Plan (or any other retiree medical plan of the Company), but who became a Participant in this Plan prior to completing the required age and service conditions to be eligible for such coverage."

2. Effective as of the closing date of the merger between Questar Corporation ("Questar") and Dominion Beehive Corp. ("Dominion Beehive"), a subsidiary of Dominion Resources, Inc. ("Dominion"), pursuant to the merger agreement between Questar, Dominion and Dominion Beehive dated January 31, 2016, the following new Schedule B is added to the Plan:

> "SCHEDULE B
> SPECIAL PROVISIONS FOR
> DOMINION QUESTAR EMPLOYEES
>
> Notwithstanding anything in Section 4.3 or any other provision of the Plan to the contrary, Employees of Dominion Questar Corporation or its subsidiaries who become Participants shall receive their Severance Payments in a single lump sum cash payment, payable as soon as administratively practicable (and in any event within 60 days) following the Participant's Scheduled Employment Termination Date."

3. In all respects not amended, the Plan is hereby ratified and confirmed.

IN WITNESS WHEREOF, the Company has caused this First Amendment to the Plan to be executed on the 15 day of September, 2016.

DOMINION RESOURCES SERVICES, INC.

By: ______________________
Wendy T. Wellener
Vice President, Human Resources

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7- 6:

Provide copies of all PowerPoint or other presentations regarding the process of Integrating departments and combining services of Dominion Energy Services, Inc. and SCANA Services, Inc. under one Services Company. This request includes, but is not limited to, presentations related to kick-off meetings with integration teams and/or other employees and all subsequent meetings regarding the integration process, including, but not limited to the integration management structure, leaders and composition of integration teams, objectives, timelines and milestones, and reporting and accountability for achievement of objectives as the integration process proceeds.

RESPONSE 7-6:

Planning for integration of SCANA with Dominion Energy continues to be in the preliminary stage, with focus on organization of the integration management structure and integration teams and rules of engagement for interactions among the integration teams. See DE Attachment ORS 7-6 Attach 1and Attachment SCANA_Attachment 1 ORS 7-6 for the current integration team for each company.

See the following attached Dominion Energy presentations:

- Attachment DE ORS 7-6 Attach 2: Presentation given to a subset of Dominion Energy Services leadership about the general process of integration and proposed integration management structure. The document assumed a kick-off meeting in April but no internal or external kick-off meeting has occurred.
- Attachment DE ORS 7-6 Attach 3 Redacted: A redacted version of a presentation given to executive leadership regarding the proposed integration approach and integration team focus. Due to the confidential and sensitive nature of the redacted information, Dominion Energy will make the unredacted version of the presentation available to ORS for review and inspection at the law offices of Nexsen Pruet, LLC after the execution of a confidentiality agreement.

- Attachment DE ORS 7-6 Attach 4: Presentation given to a subset of Dominion Energy Services leadership providing an integration planning status update.
- Attachment DE ORS 7-6 Attach 5: Template presentation used for various internal integration planning status update meetings in June.

See the following attached SCANA presentations:

- Attachment SCANA_Attachment 2 ORS 7-6: a late January SCANA only kickoff that included certain rules of engagement.
- Attachment SCANA_Attachment 3 ORS 7-6: March update to the SCANA Officers' Meeting.
- Attachment SCANA_Attachment 4 ORS 7-6: May update to SCANA's Board of Directors.
- Attachment SCANA_Attachment 5 ORS 7-6: March and April updates made to various departments within the company.

Formal kick off meetings between SCANA and Dominion Energy have not been scheduled at this time. As material components of the integration plan are finalized, updated information will be provided.

RESPONSIBLE PERSON: Karla Haislip (Dominion Energy) and Joanna Greene (SCANA/SCE&G)

Dominion Energy/SCANA Merger Transition Team

SCANA Attachment 1 ORS 7-6

Area	Individual	Service Co Proj Leads	Title	Location
Executive Sponsor	Iris Griffin		SVP - CFO and Treasurer	CHQ D
Overall	Joanna Greene		Director	CHQ A
Service Company				
IST	India Mack	Mack	Technology Consultant	CHQ A
IST	Andrea Peterman	Peterman	Technology Consultant	VCS/CHQ A
IST - Infrastructure	Ron Bryant	Mack	Director - IT	CHQ A
IST - Cyber	Andy Bowden	Mack	Director - IT	CHQ A
IST - Applications	Guy Bradley	Peterman	Director - IT	VCS/CHQ A
Financial Planning/Treasury/Corp Credit/Invst Rel	Christina Putnam	Putnam	Mgr-Financial Planning	CHQ C
Accounting	Lisa Honeycutt	Putnam	Mgr-Electric & Gas Accounting	CHQ B
Human Resources	Matt Stanton	Stanton	Director - Human Resources	CHQ C
Corporate Security	Tony Elliott	Stanton	Director - Corp Security and Claims	CHQ D
Corporate Planning	Betty Best	Best	Director - Strategic Planning	CHQ B
Strategic Sourcing	Charles Marshall	Best	Mgr - Sourcing	CHQ D
Facilities	Barry McDonald	Best	Gen Mgr - Facilities & Land	CHQ D
Fleet	Annette Burnette	Best	Business Mgr - Fleet	Cola Fleet
Marketing and Communications	Terri Randall	Best	Sr Spec-Communications	CHQ B
Aviation/Safety (SCANA Services)	Rick Boyer	Best	Mgr - Aviation	Aviation Way
Legal/Claims	Elizabeth Hutton	Hutton	Asst General Counsel	CHQ C
Econ Dev/Govt/Regulatory Affairs	Rachel Robinson	Hutton	Mgr - Electric & Gas Reg Acctg	CHQ C
Corporate Compliance and Audit Services	Jean Hiers	Hutton	Mgr - Compliance	CHQ B
Risk Management/FERC Compliance	Catherine Taylor	Hutton	Director - Risk Mgt & Deputy Gen Counsel	CHQ C
Corporate Secretary/Records Management	Ann Hutchens	Hutton	Director - Corporate Records	CHQ D
Environmental	Tom Effinger	Hutton	Director - Environmental Services	CHQ C
Operations				
Nuclear	George Lippard		VP Nuclear Operations	VCS
Electric Transmission	Jamie Starling		Mgr - ERO Compliance	TOC
Retail Technology/Renewables/System Ops/Elect Ops	Craig Aull		Gen Mgr - Retail Technology Syst	OSC
Wires Business	Shannon Kochems		Mgr - CIS Financial Adminstration	OSC
Elect Trans/Const	Shannon Perry		Project Mgr - NND Transmission	TOC
Fossil Hydro/Fuel Procurement	Gene Delk		Gen Mgr - Fossil Opns	CHQ A
SCANA Energy	Brett Newsom		Director - Reg Affairs/Mkt SCANA Energy	Atlanta
Customer Service	Pat Miller		Mgr - Contact Center	24/7
Gas Operations	Scott Swindler		Gen Mgr - Operations and Maintenance	Gastonia

DE Attachment ORS 7-6 Attach 1

	Area
tegration and Stratgic Change	Integration Lead
Change and Project Manager	Integration Project Management
	Accounting
	Audit
viation and Travel	Aviation/Travel
liance	Corporate Risk/Credit/Insurance
Security	Corporate Safety/Corporate Security
tary and Director Governance	Corporate Secretary
tal Services	Environmental
ompliance	Ethics and Compliance
n Project Manager	Facilities
	Financial Planning - Services
l Project Manager	Human Resources
ations	Investor Relations
Account	IT
	Legal
licy, Strategy & Outreach Policy	Philanthorpy/Advertising/Branding/Federal and
ates and Regulation	Regulatory
in Services	Supply Chain/Strategic Sourcing/Fleet
	Tax
Disbursments	Treasury - Cash Management/Finance
Acquistions	Treasury - Coporate M&A

Grant Neely	Director Corporate Communications
Richard Davis	
LD Wade	
Sam Luu	
Jeff Murphey	
Todd Johnson	

Communications
Treasury - Corporate Finance
Treasury - Corporate Risk - Insurance
Treasury - Credit
Gas Regulation
Records Management

Transition Team

Internal Kickoff

January 25, 2018

Agenda

- Rules of Engagement with Dominion
- Privacy and other regulatory concerns
- Sharing of information how to's
- High level game plan
- Merger SharePoint site

Rules of Engagement

- Guidelines based on:
  - Antitrust Gun-Jumping Guidelines
  - Securities Law Guidelines
  - Merger Agreement
- Guidelines document is a reference point and is not comprehensive – please contact appropriate subject matter expert with questions
  - Joanna Greene – overall transition team
  - Elizabeth Hutton – legal
  - Will Brumbach – legal
  - Kevin Painter – data classification

Antitrust Gun-Jumping Guidelines

- SCANA and subsidiaries must
  - Operate independently from Dominion Energy
  - Limit exchanges of competitively sensitive information with Dominion
    - Current/prospective pricing information
    - Marketing and sales plans (including new product offerings)
    - Current/prospective customer, vendor or competitor information
    - Cost or profit information

Antitrust Gun-Jumping Guidelines

- Dominion Energy may, and SCANA may work with Dominion to:
  - Plan for (but not implement) post-merger personnel and benefits matters
  - Plan for (but not implement) any branding/name changes
  - Explore compatibility of systems architecture and technology with SCANA

Securities Law Guidelines

- Overarching idea is that:
  - The entire market should have (a) nearly simultaneous access to (b) written or recorded statements (c) SCANA makes (d) in an effort to convince shareholders to vote for the merger.
  - Those who receive these statements need to be warned regarding certain topics

Securities Law Guidelines

- Any written or recorded statements that are made by SCANA (or made by others, including Dominion, and adopted by SCANA such as by providing a link to third party statements) that could be viewed as being likely to encourage SCANA shareholders to vote in favor of the merger must contain certain required cautionary legends and be filed with the SEC
  - Written or recorded presentations or communications that discuss the benefits of the merger to employees (many of whom are SCANA shareholders), or that discuss material new information about the merger, such as strategic plans following the merger
  - Written or recorded presentations that are made at investor conferences

Securities Law Guidelines

- Takeaways:
  - Limit your communications to approved messages provided by SCANA Public Affairs and Corporate Communications
  - Do not create your own written notes or talking points
  - If you receive questions that are beyond the scope of the approved messages please direct to Joanna Greene

Merger Agreement Guidelines

- General Rule – SCANA shall conduct its business in ordinary course consistent with past practice except as otherwise specified
- Both parties must:
  - Keep each other informed as to status of submissions and filings
  - Keep each other informed of any developments with third parties or any governmental entity, discuss in advance any written response and provide an opportunity to participate to extent practical
  - Consult with each other prior to issuing any press release or public statement with respect to the merger

Merger Agreement Guidelines

- Both parties must (continued):
  - Provide reasonable access to employees, books, records and properties (excluding invasive environmental testing or sampling) in a manner that does not unreasonably interfere
  - Preserve the confidentiality of any confidential information
  - Promptly advise each other of any change that has or is reasonably likely to cause a Material Adverse Effect or a material breach
  - Not take any action that would be reasonably expected to prevent, or materially impair or delay, the consummation of the merger

Merger Agreement Guidelines

- With respect to litigation:
  - Shareholder litigation - SCANA must advise Dominion of any shareholder litigation and not settle without consent
  - Nuclear litigation – SCANA shall
    - notify Dominion of receipt of any material communication related to any material claim... relating to construction or stopping construction of units 2 and 3
    - Keep Dominion reasonably informed of any developments
    - Give Dominion notice of any material meetings or discussions

Merger Agreement Guidelines

- With respect to settlements (other than Nuclear):
  - SCANA shall not settle any claim...which provides injunctive relief material to SCANA or requires payment in excess of $10m other than ordinary course of business or an amount reflected in the reserves on company's financial statements

Merger Agreement Guidelines

- The merger agreement restricts certain actions of SCANA relating to:
  - Dividends; reclassification of capital stock or purchase or redemption of capital stock; or issuance of capital stock or convertible securities;
  - Amendment of organizational documents;
  - Acquisitions/investments or asset disposition;
  - Indebtedness
  - Capital expenditures (ok within $50m of budget or emergency/safety)
  - Compensation and equity awards;
  - Accounting method changes (may not make such changes that would reasonably be expected to be material unless required by GAAP, a Governmental Entity or Law);
  - Taxes (may not make/change any material Tax election, Tax accounting period or material method of Tax accounting; may not settle or compromise any material Tax liability or consent to any material claim or assessment or obtain any material ruling relating Taxes; file any amended Tax Return; or enter into any material closing agreement relating to Taxes);
  - Modification of Material Contracts and entering into Material Contracts;
  - Corporate reorganization,
  - IT Systems - may not materially change or enter into any IT Systems or cyber-security Contracts that are material to SCANA other than routine maintenance and upgrades to existing IT Systems

Data Classification

- Our data classification obligations are not trumped by merger agreement
- For now focus on processes, least amount of data provided
- Any sharing of customer, employee or other data elements need to be reviewed for appropriate classification protection
- Sharing of contract provisions we have with third parties also needs to be assessed
- Receipt of information needs to be controlled in similar manner
- When in doubt - ask

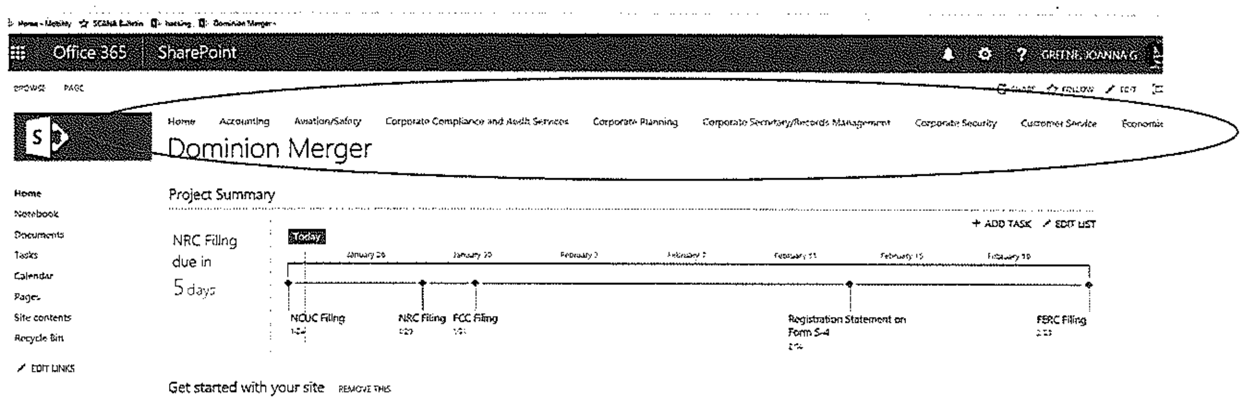
Current Sharing Processes

- "Due Diligence" e-room with attorneys is still in place and being used for specific data requests around due diligence efforts
- "Transition" e-room on Dominion side has been restricted to Dominion only at this point
- Emails to all @dominionenergy.com addresses are being encrypted in transport and also copied off to internal legal hold
- Sharepoint file share options will be established once Dominion e-room is opened up to SCANA
- If email is not appropriate or does not work for specific information share please contact India Mack or Andrea Peterman for alternatives

Expected High Level Game Plan

- Q1 thru closing date:
  - Focus primarily on processes and procedures – best practices
  - Some inventory and analysis of IT systems and evaluation of integration options
  - Day 1 critical items anticipated to include:
    - Accounting – ability to close books with SCANA providing financial information for a 3 day close
    - Directory – ability for employees to look up any Dominion or SCANA employee from same directory
    - Free/Busy – view calendar availability for any Dominion/SCANA employee
    - Job Postings – ability for Dominion/SCANA employees to see all jobs open across organization
- Post Close thru 1/1/2020
  - Peoplesoft to SAP conversion for Financial and HR
- Organizational analysis will take place throughout the transition based on individual area needs and requirements

Merger SharePoint Site



Merger SharePoint Site

- Will eventually have folder on each site that will be used to "transfer files to Dominion" - until then just leverage site for internal team documents as needed
- Transition team member is responsible for granting site access – email instructions will be provided and saved on overall merger site
  - Access reports will be generated for review on periodic basis
- Access to Office 365 is required – if you have not yet enabled your Office 365 account and MFA you will need to – instructions will be provided by email

TRANSITION UPDATE

MARCH 7, 2018

WHERE ARE WE NOW

Storm Management

- Pre Storm Notification
- Day 3 storm alert condition
  - Verification
  - Communication
  - Planning
  - Ensuring coverage
  - Assessing systems

INTEGRATION

Planning
- Develop integration strategy and plan

Analysis
- Conduct detailed integration analysis

Execution
- Define the future

Transition
- Unwind transition services and stand up new processes/org

WHAT WE'VE DONE

- IDENTIFIED JOINT INTEGRATION MGMT OFFICE AND SCANA TRANSITION TEAM
- DEFINED RULES OF OPERATION – ANTITRUST, SEC, MERGER AGREEMENT
  - HELD INTERNAL KICKOFF MEETING 1/25
- ESTABLISHED WEEKLY UPDATE MEETINGS WITH SUBSET OF TRANSITION TEAM
  - FIRST WEEKLY UPDATE SUMMARY WAS MOST CLICKED ON HEADLINES ARTICLE
  - TEAM HAS APPRECIATED SENIOR STAFF INVOLVEMENT IN MEETINGS
- HELD BI-WEEKLY/WEEKLY COMMUNICATIONS MEETINGS WITH DOMINION
  - CURRENTLY IN PROCESS OF RE-ESTABLISHING THESE MEETINGS

WHAT ELSE WE'VE DONE

- PRELIMINARY ALIGNMENT OF SCANA ORGANIZATION WITH DOMINION ORGANIZATION

example

Dominion Area	SCE&G	PSNC	SEMI	Service Co	Grand Total
Accounting				31	31
Accounting/BU Finance				43	43
Audit				17	17
BU Environmental	22				22
BU IT	14			43	57
BU Safety & Health	[illegible]			4	13
COMBO				91	91
Community Affairs			4	35	39
Corp Environmental				29	29
Corp IT				485	485
Corp Safety & Health				2	2
Corporate Communications				11	11
Corporate Finance				29	29
Corporate Risk				11	11
Corporate Security				44	44
Corporate Strategy				17	17
Cust Svc				272	272
Cust Svc - GA				105	105
E&C				3	3
Enterprise Risk				22	22
Executive	11	2	4	33	50
Fleet	67	20		18	105
GIG	336	629	66	116	1147
Governance				1	1
Govt Affairs				15	15
HR				69	69

WHAT ELSE WE'VE DONE

- CONDUCTED ONE DAY HR PROCESS OVERVIEW WITH DOMINION
- WORKED WITH WILLIS TOWERS WATSON AND DOMINION ON BENEFITS COMPARISON
  - SIGNED AGREEMENT TO ALLOW WTW TO SHARE INFORMATION ON BOTH COMPANIES
  - COMPLETED DATA REQUESTS
- UPDATED EMPLOYEE CENSUS FOR DOMINION AFTER MERIT PROCESSING
- DEVELOPED POSITION TRACKING PROCESS TO MANAGE ATTRITION, VACANCIES, ETC.
- UPDATED EE FAQ ON MERGER SITE – ON TRACK TO CONTINUE EVERY TWO WEEKS

WHAT ELSE WE'VE DONE

- CONDUCTED ONE DAY IT INFRASTRUCTURE OVERVIEW WITH DOMINION
  - FOCUS ON DATA CENTER OPERATIONS TO DETERMINE OPTIONS TO 1401 MAIN
- CONDUCTED TWO SESSIONS BETWEEN SCANA ACCOUNTING/CIS AND DOMINION
  - EVALUATING OPTIONS FOR 3 DAY CLOSE REQUIREMENT
  - APPEAR TO PRIMARILY BE PROCESS CHANGES AT THIS POINT

WHAT ELSE WE'VE DONE

- CONDUCTED JOINT DIVERSITY DISCUSSION AROUND BEST PRACTICES AND 2018 GOALS BETWEEN DOMINION DIVERSITY LEADERSHIP AND SCANA DIVERSITY STEERING COMMITTEE
- HELD PLANNING SESSION FOR JOINT INTEGRATION MGMT OFFICE
  - REVIEWED QUESTAR INTEGRATION LESSONS LEARNED
  - DETERMINED PRIORITIES FOR EVALUATING ORGANIZATIONAL DESIGN AND BUSINESS PROCESSES
  - IDENTIFIED RESOURCE NEEDS FOR TRANSITION TEAM
  - BEGAN DISCUSSION ON DATA GATHERING PROCESS

WHAT ELSE WE'VE DONE

- FOUGHT FIRES
  - QUESTIONS AROUND COMMUNICATION WITH DOMINION
  - QUESTIONS FROM DOMINION ABOUT CUSTOMERS, ADVERTISING, ETC
  - QUESTIONS ABOUT HOW CONTACT CENTERS RESPOND TO QUESTIONS
  - QUESTIONS AROUND EXISTING PROJECTS
  - QUESTIONS AROUND JOINT COMMUNICATIONS TO CUSTOMERS
  - COMMUNICATIONS REVIEWS

RULES OF ENGAGEMENT (HIGHLY CONDENSED VERSION!)

- OPERATE INDEPENDENTLY (PLANNING FOR FUTURE IS ALLOWED)
- LIMIT EXCHANGES OF COMPETITIVELY SENSITIVE INFORMATION
- FILE ALL WRITTEN/RECORDED COMMUNICATIONS SUPPORTING MERGER WITH SEC
- KEEP EACH OTHER REASONABLY INFORMED AND PROVIDE REASONABLE ACCESS
- PRESERVE CONFIDENTIALITY OF ANY CONFIDENTIAL INFORMATION
- NOT TAKE ANY ACTION THAT WOULD PREVENT OR DELAY MERGER
- CERTAIN ACTIONS ARE RESTRICTED BY MERGER AGREEMENT

WHEN IN DOUBT - ASK

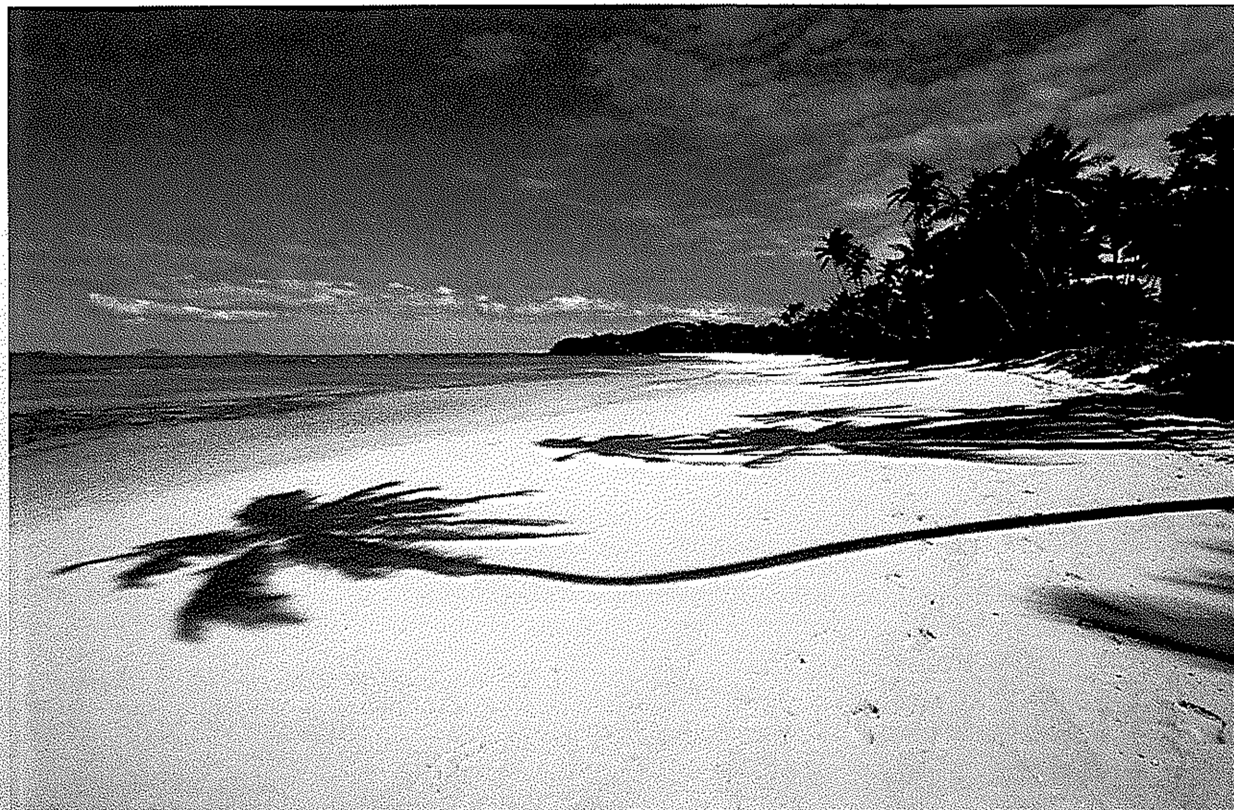
LESSONS DOMINION LEARNED

- COORDINATED AND TIMELY COMMUNICATION IS KEY
  - NEEDS TO FLOW THROUGH INTEGRATION MGMT. OFFICE TO ENSURE COORDINATION
- SIGNIFICANT MAGNITUDE OF CHANGE
  - NEED TO IDENTIFY WAYS TO EASE TRANSITION PROCESS AND BEGIN TO LESSEN IMPACT AT CLOSE/CUTOVER
- DEDICATED RESOURCES ARE A MUST FOR CERTAIN FUNCTIONS

LESSONS QUESTAR LEARNED

- IMPORTANCE OF AWARENESS OF ALL TRANSITION/MERGER ACTIVITIES
  - NO ROGUE OPERATIONS
  - BIG PICTURE VIEW OF IMPACTS OF CHANGES
- IMPORTANCE OF DEDICATED RESOURCES
- APPRECIATION OF LEVEL OF COMMUNICATION REQUIRED
  - FACE TO FACE WITH GROUPS WHEREVER POSSIBLE
  - CHANGE AGENT NETWORK WITH FEEDBACK LOG

WHERE WE HOPE TO BE!



Dominion Energy, Inc.

Human Resources Update

June 12, 2018

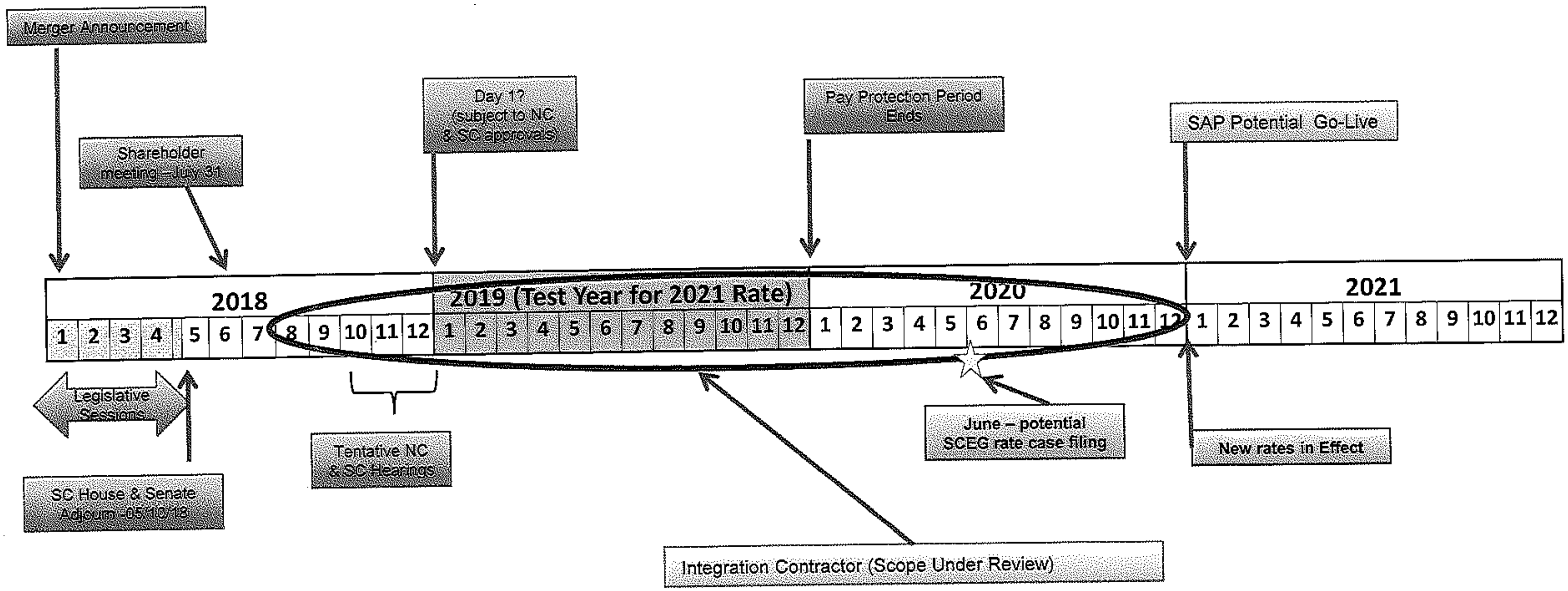
Dominion Energy®

Merger Commitments

- Merger Commitments
  - Maintain SCE&G headquarters in Cayce, SC
  - $1 M increase in charitable giving for 5 years
  - $1.3 B cash payment within 90 days to average customers
  - Minimum 5%-7% bill reduction
  - Acquisition cost of natural-gas fired power station absorbed by shareholders
- Employee commitments
  - Pay continuation through 12/31/2019: Base pay and bonus plan target amounts at least equal to levels at close
  - Position eliminations: Individuals are eligible for base pay continuation through 12/31/2019 or the Dominion Energy Severance Plan, whichever is greater
  - Current active health and welfare benefit plans and policies will likely remain in place through 12/31/2019: Your years of service with SCANA will be recognized as service with Dominion Energy for policy purposes
  - Retirement Benefits through 12/31/2019: Pension, 401(k) and Retiree Medical
  - Employment Opportunities: accessible across the company at close
  - Retirement plan transition determined 3Q2018
  - Military full time employees will be granted up to 120 hours paid time off
- Legislative and Regulatory timing uncertainty

Integration Timeline

(DRAFT High Level – Estimated)



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Questar Lessons Learned

- Faster access to systems
- Schedule prioritized over a longer period
- Additional/Dedicated Resources to Support Integration
  - Functional teams
  - Project management support (scheduling, communications, and data analytics)
- Training/Testing
  - Dedicated training environment
  - Dedicated testing environment
  - Dedicating functional team resources for training development
- Utilizing "Change Agent Network" earlier in future projects
- Timely decision making on organizational alignment and related system issues

Best Practices
(Review of Multiple Merger Integration Models)

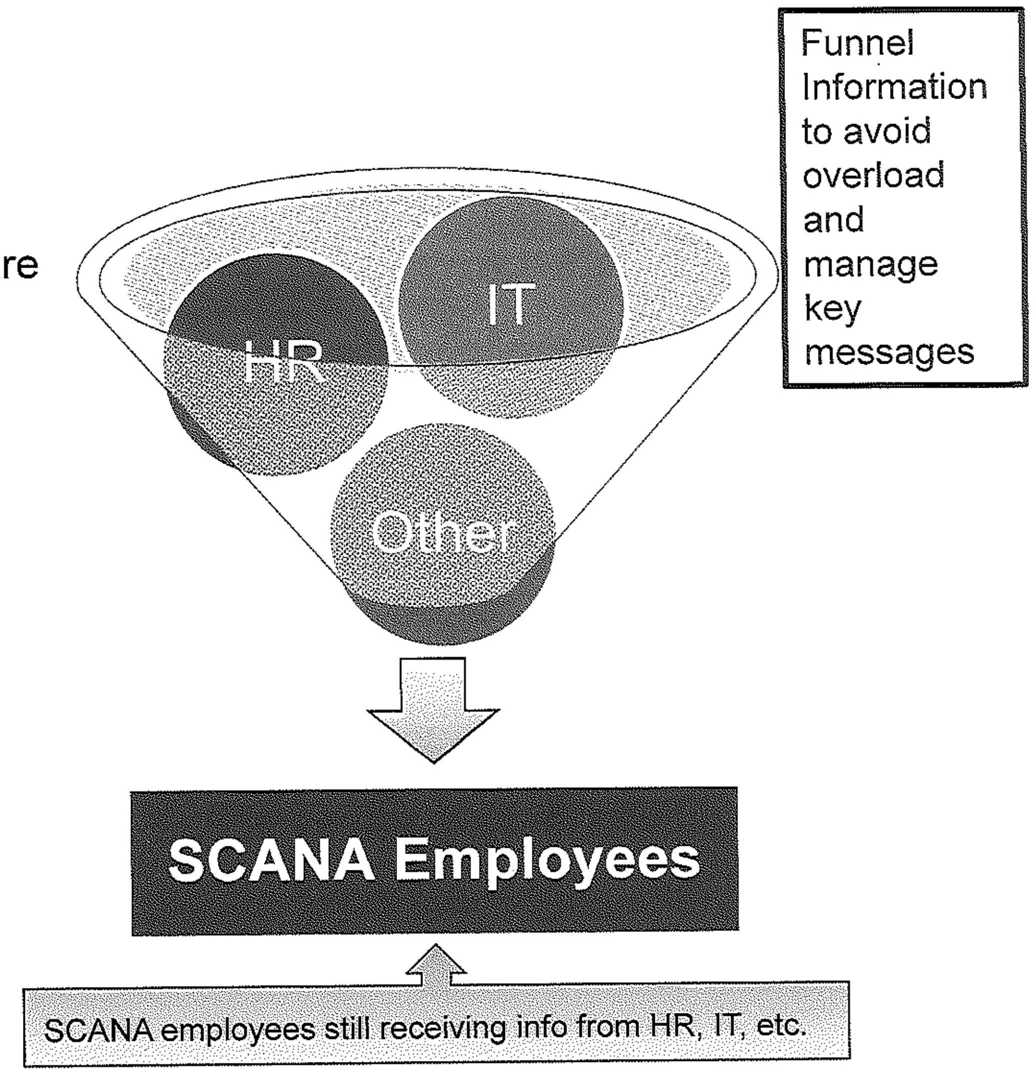
1. Define the Integration Model, Roles, Responsibilities and Governance
   - Steering Committee Roles and Responsibilities, Expectations, Vision Communicated
2. Articulate the Operating Model
   - Single Shared Company? Operating along business lines? Platforms?
3. Formally Launch the integration process
   - Set Objectives and Priorities
4. Day to Day involvement with leadership
5. Day 1 Priorities
6. Communicate
7. Tailor the Change Management Approach
   - Educate
   - Define vision for new company
8. Maintain integration process continuity
   - Preserve the integration team: Start to end state
9. Align outcomes and incentives

Best Practices
(Review of Multiple Merger Integration Models)

7. **Tailor the Change Management Approach**
   - Educate
   - Define vision for new company
8. **Maintain integration process continuity**
   - Preserve the integration team: Start to end state
9. **Align outcomes and incentives**

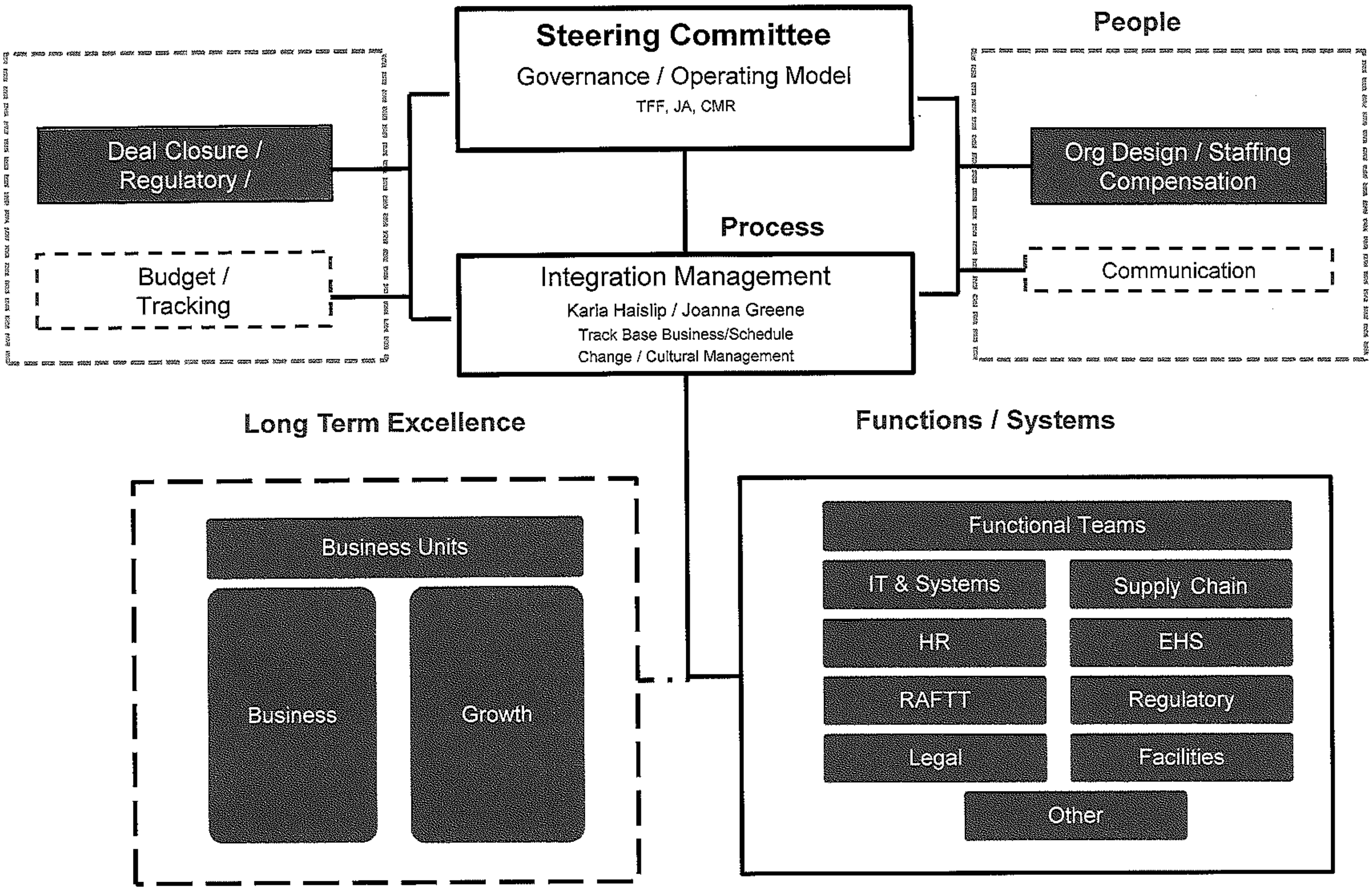
Communication

- Single Integration Voice - Clear
- Communicate themes, not just events
- Be transparent and clear on what we are trying to accomplish
- All need communication
  - Not just those undergoing change



Integration Management Organization

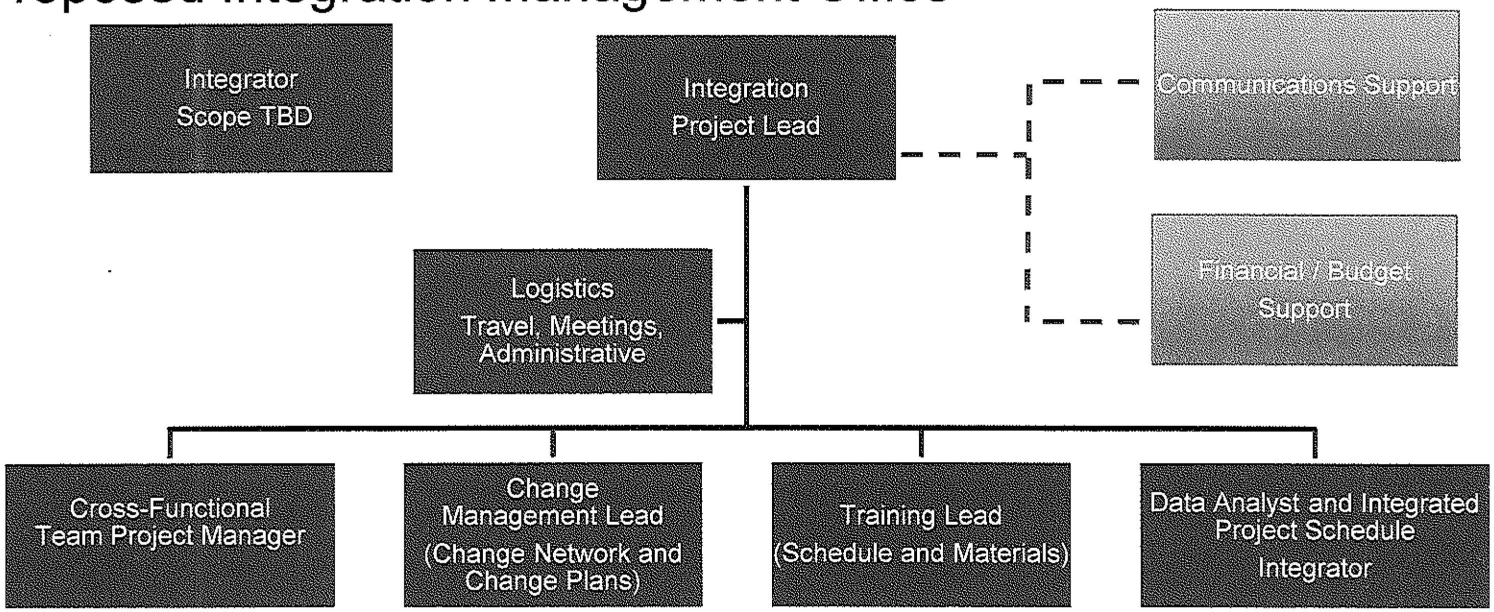
Review underway for Integration Support



Integration Management Office (IMO)

Resources: Internal and Integrator / Contractor Support

- Proposed Integration Management Office



- Functional teams need to determine resource requirements considering:
  - Time frames: now to "Day 1", post close/pre SAP, after go live
  - Identify risks/staffing constraints
  - Use of integrator and impact to staffing needs

Functional Transition Team

Overview and Expectations

- Collect baseline data
  - Note similarities and differences
- Serve as liaisons for their respective departments
- Lead SMEs in their area to address transition issues related to their departments and articulate business case for gaps.
- Provide guidance as needed on decisions that may impact their area(s).
- Identify and create task plans for their area.
  - Day 1 and other key decision points
- Collaborate and involve other areas where interdependencies arise

LEAD and Collaborate

The Integration Process

A sequential and staged approach to design and execution

Key Stages	Framework Development	Analysis	Design	Implementation Planning	Implementation
Scope	Plan the effort	Build the facts	Define the future	Prepare for change	Operate as one
Key Activities	• Refine the vision • Develop the approach • Set the expectations • Team Design	• Baseline understanding of each others processes • Identify constraints • High level task lists • Comparison summary	• Define options • Build structure • Align processes • Establish metrics	• Define requirements • For Day 1 • Develop priorities • Build detailed task plans • Define sequence • Check-lists	• Establish responsibilities • Develop hand-offs • Integrate operations • Capture synergies • Operating plan

*Timing and Durations are approximate, some areas of integration will be on a faster track than others and phases will overlap

Transition Update

May 2018

SCANA_Attachment 4 ORS 7-8

Where we are now

Storm Management
- Pre Storm Notification
- Day 3 storm alert condition
  - Verification
  - Communication
  - Planning
  - Ensuring coverage
  - Assessing systems

Integration

Planning
- Develop integration strategy and plan process

Analysis
- Conduct detailed integration analysis

Execution
- Define the future and implement day 1

Transition
- Unwind transition services and stand up new processes/org for day 2

What Dominion has done

- Conducted Questar lessons learned jointly with Questar team
  - Communication and coordination
  - Resource commitment
  - Magnitude of change
- Assessed need for integrator – currently out for RFP
  - Clean room – independent assessment
    - Eliminates actual or perceived risk of anticompetitive behavior
    - Allows gathering and examination of sensitive or competitive data
  - Program management

What we've done

- Identified joint Integration mgmt office and SCANA transition team
- Defined rules of operation – antitrust, SEC, merger agreement
  - Held internal kickoff meeting 1/25
- Established weekly update meetings with subset of transition team
  - First weekly update summary was most clicked on Headlines article
  - Team has appreciated senior staff involvement in meetings
- Held bi-weekly/weekly communications meetings with Dominion

What else we've done

- Conducted one day HR process overview with Dominion
- Performed preliminary alignment of SCANA organization with Dominion organization
- Worked with Willis Towers Watson and Dominion on benefits comparison – scheduled to be provided to employees in q3
- Developed position tracking process to manage attrition, vacancies, etc.
- Established update cadence for employee FAQ on merger site
- Conducted joint diversity discussion around best practices and 2018 goals between Dominion diversity leadership and SCANA diversity steering committee

What else we've done

- Conducted one day IT infrastructure overview with Dominion
  - Focus on data center operations to determine options to 1401 Main
- Conducted multiple sessions between SCANA accounting and Dominion
  - Evaluating options for 3 day close requirement
  - Appear to primarily be process changes at this point
  - Will require separate revenue close and billing close for billing system
- Established process to grant Dominion integration team physical and network access to SCANA facilities and integration SharePoint site (will leverage SCANA managed site)

What else we've done

- Fought fires
  - Questions around communication with Dominion
  - Questions from Dominion about customers, advertising, etc
  - Questions about how contact centers respond to questions
  - Questions around existing projects
  - Questions around joint communications to customers
  - Communications reviews

What we plan to do

- Kick off in q2
- Organize by functional areas – initially support service focused
- Focus on best practices and synergies
  - Identify and implement early wins where appropriate
- Plan for Day 1 (close)
  - Ability to close books together in a timely manner
  - Ability for employees to look up other employees and view free/busy
  - Ability for employees to view job postings across organization
- Plan for Day 2 (integrated systems – anticipated 1/1/2020)
  - Conversion of SCANA Peoplesoft to Dominion SAP
  - Integration of organizations

Rules of engagement (highly condensed version!)

- Operate independently (planning for future is allowed)
- Limit exchanges of competitively sensitive information
- File all Written/recorded communications supporting merger with sec
- Keep each other reasonably informed and provide reasonable access
- Preserve confidentiality of any confidential information
- Not take any action that would prevent or delay merger
- Certain actions are restricted by merger agreement

When in doubt - ask

Dominion Energy, Inc.

SCANA Update

June xx, 2018

Dominion Energy®

Merger Commitments

- Merger Commitments
  - Maintain SCE&G headquarters in Cayce, SC
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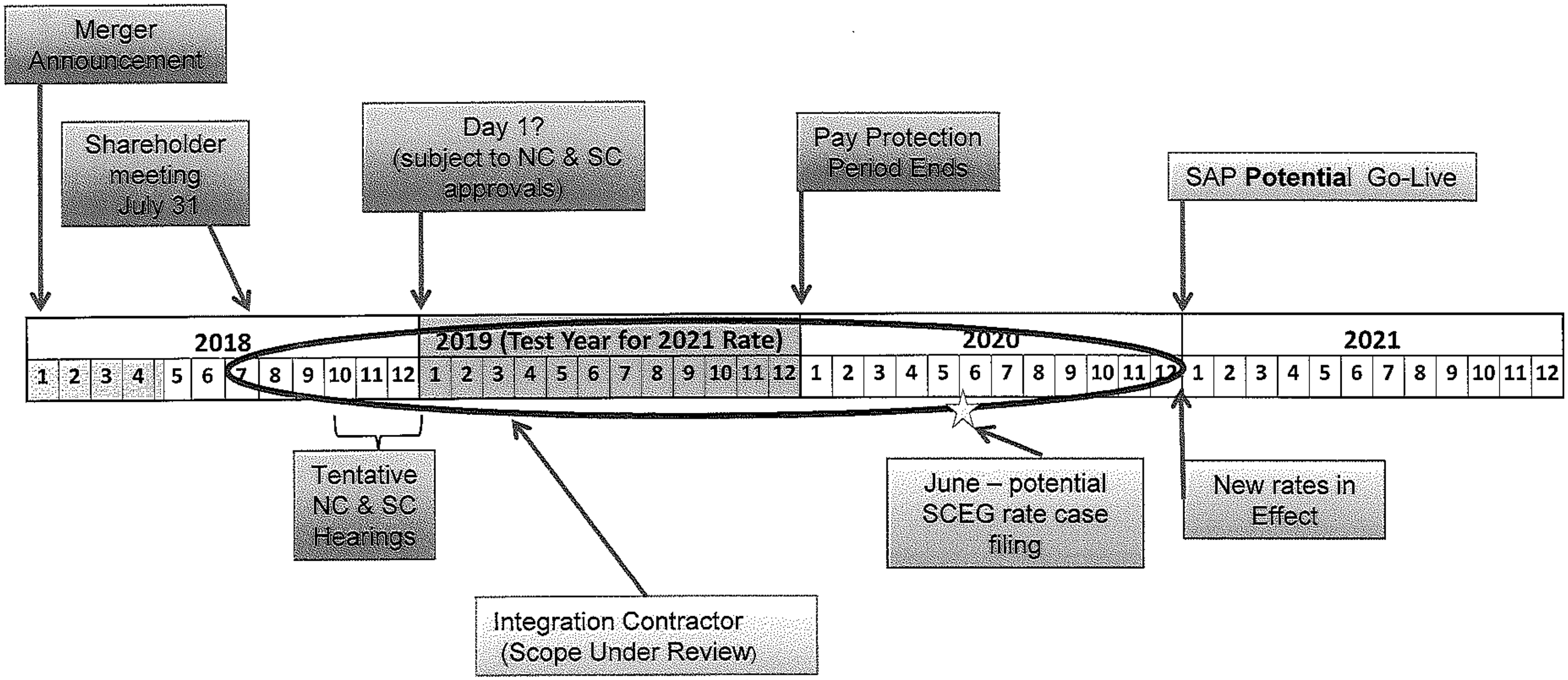
Integration Timeline

(DRAFT High Level – Estimated)



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- Training/Testing
  - Dedicated training environment
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- Timely decision making on organizational alignment and related system issues

Best Practices
(Review of Multiple Merger Integration Models)

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6. Communicate
7. Tailor the Change Management Approach
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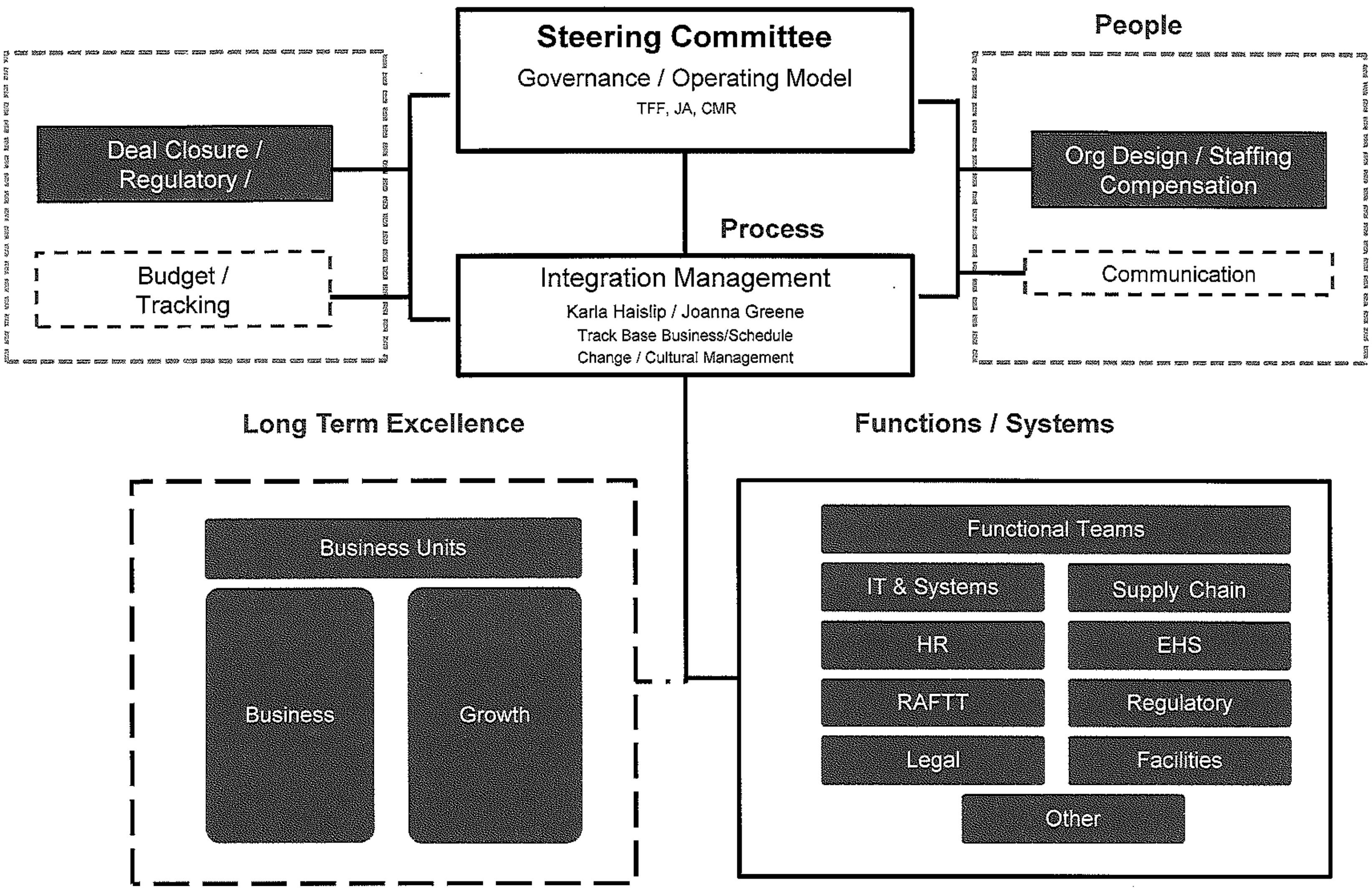
Integration Management Organization

Review underway for Integration Support



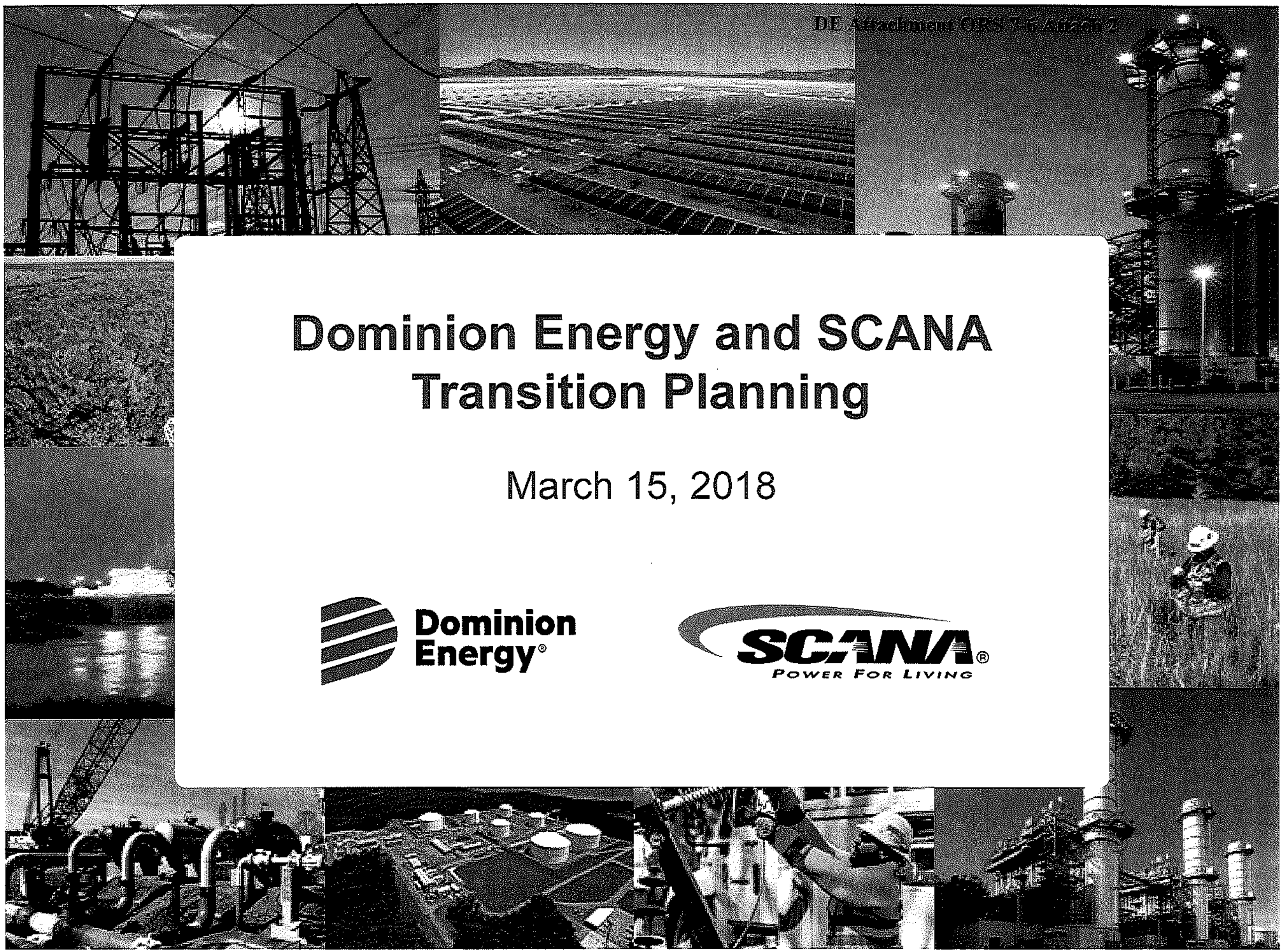
Functional Transition Teams

Overview and Expectations

- Collect baseline data
  - Note similarities and differences
- Functional leads serve as liaisons for their respective departments
- Lead SMEs in their area to address transition issues related to their departments and articulate business case for gaps.
- Provide guidance as needed on decisions that may impact their area(s).
- Identify and create task plans for their area.
  - Day 1 and other key decision points
- Collaborate and involve other areas where interdependencies arise

LEAD and Collaborate

DE Attachment ORS 7-6 Attach 2



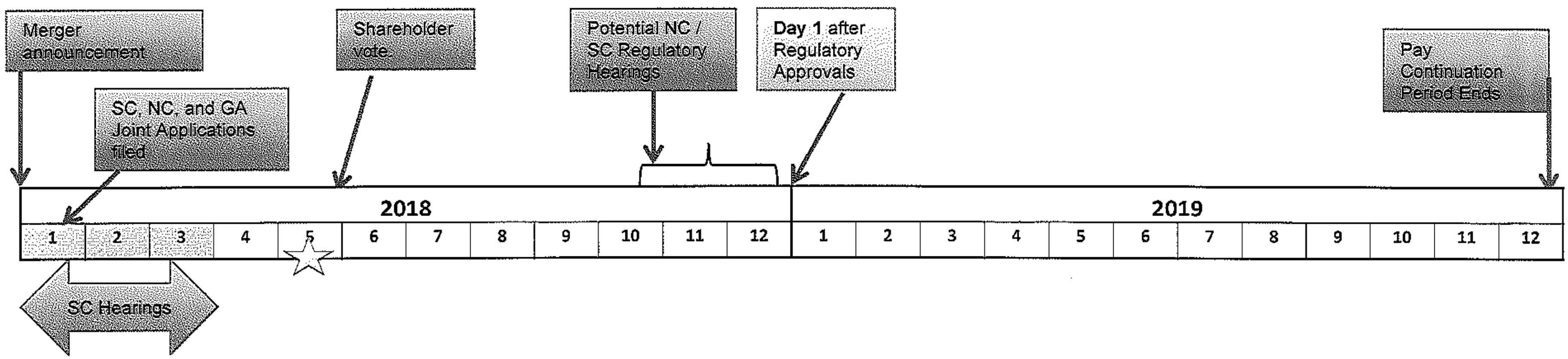
Dominion Energy and SCANA Transition Planning

March 15, 2018

Dominion Energy®

SCANA® POWER FOR LIVING

Merger Timeline (High level - Estimated)



Activities from January to <u>Now:</u>

- Joint applications for regulatory approvals made in SC, NC, and Georgia
- Two out of five federal approvals received, all expected by August 2018
- Monitoring/participating in the SC House and Senate hearings on cost recovery of VC Summer project
- Engagement in regulatory process with all 3 states
- Community outreach underway in SC and NC
- Developing strategy on go forward integration model and process
- Assessment of PwC recent activities supporting Questar merger
- Review potential "Integration support" for large scale integration

- Extensive review of lessons learned from Questar merger

Recommendations for future mergers

- **Faster access to systems**
- **Schedule prioritized over a longer period**
- **Additional/Dedicated Resources to Support Integration**
  - Dedicated full-time resources for functional teams
  - Additional full-time dedicated resources in Project Management (scheduling, communications, and data analytics)
- **Training/Testing**
  - Dedicated training environment to enable earlier training materials development and "hands-on-keyboard" training of systems and processes
  - Dedicated testing environment, include more stakeholders and time for testing
  - Dedicating functional team resources for training development
- **Utilizing "Change Agent Network" earlier in future projects**
- **Timely decision making on organizational alignment and related system issues**

Best Practices Overview
(Review of Multiple Merger Integration Models)

1. **Define the Integration Model, Roles and Responsibilities and Governance**
   - Steering Committee Roles and Responsibilities
   - Team Leads Expectations
   - Clear vision communicated to team: Best of Both? Transformation? Absorption?
2. **Articulate the Operating Model**
   - Single Shared Company? Operating along business lines? Platforms?
3. **Formally Launch the integration process**
   - Set Objectives and Priorities
   - Document and report to leadership
4. **Day to Day involvement with leadership**
   - Support, buy in, expectations
5. **Challenge the teams/Align incentivize**
   - Day 1 Priorities?
6. **Communicate**
   - Single Integration Voice
   - Transparency - Communicate what you know when you know it
   - Communicate themes, not just events

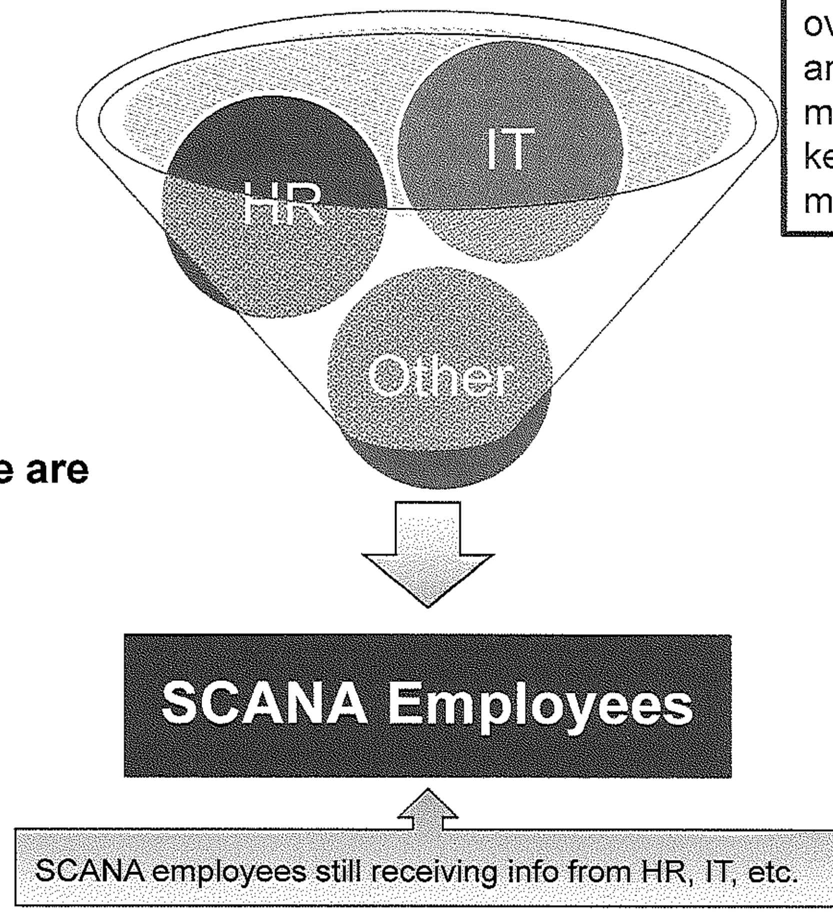
Best Practices
(Review of Multiple Merger Integration Models)

7. **DAY ONE**
   - Execute Day 1 requirements
   - Clear integration plans to move to one entity, tactical plans for synergies best practices
8. **Tailor the Change Management Approach**
   - Educate
   - Define vision for new company
9. **Maintain integration process continuity**
   - Preserve the integration team, if it moves from designing the end state to actually making it work
10. **Closely track initiatives and dollars**
11. **Align outcomes and incentives**

Communication Recommendations

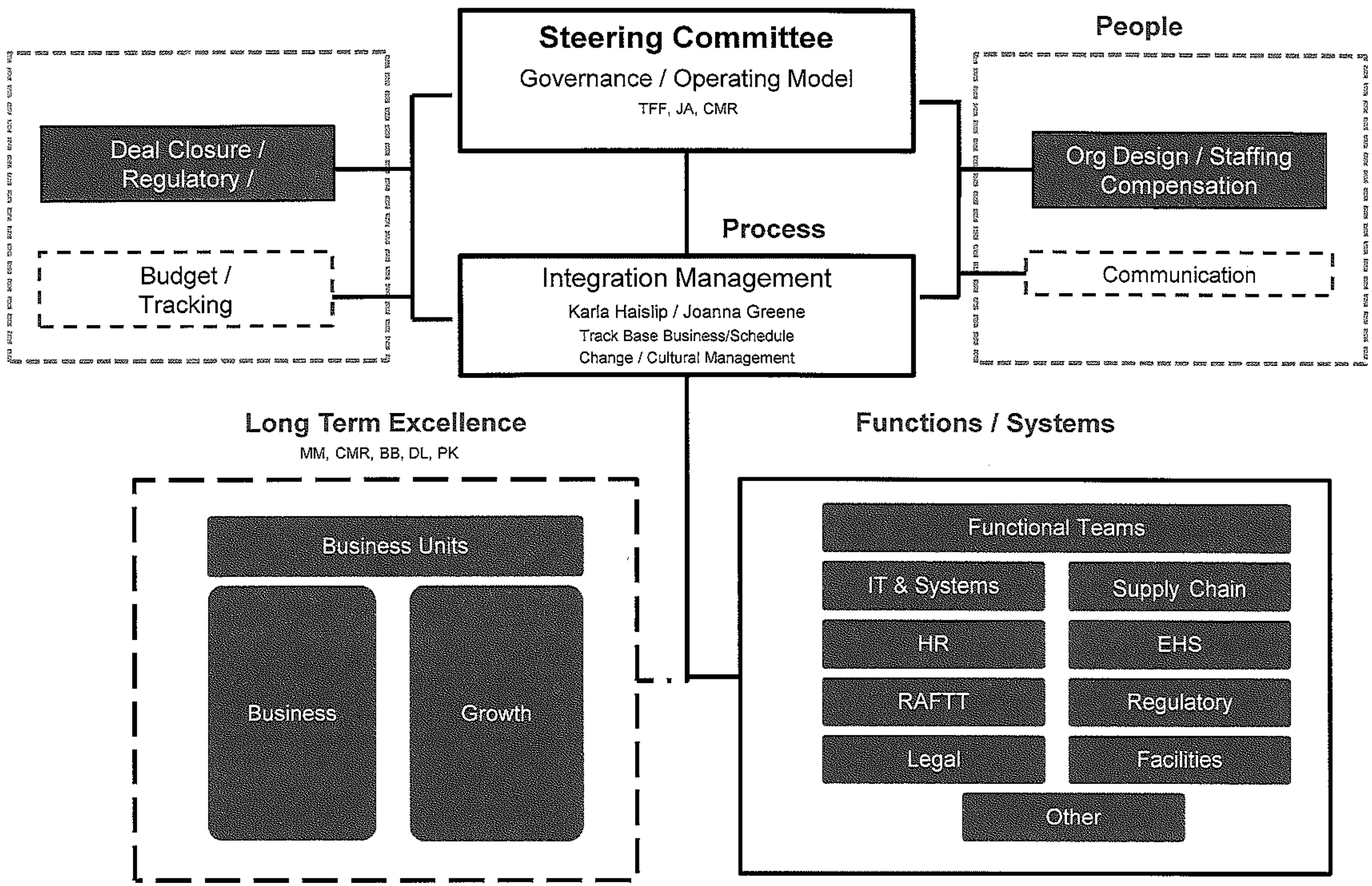
- **All communications go through Communication Review Committee**
- **Clear Messaging from Single Source**
- **One Voice**
- **Don't give false sense of assurance**
  - We are similar
  - Cultures are alike
- **Be transparent and clear on what we are trying to accomplish**
  - Earnings Per Share?
  - Reductions ?
- **All need communication**
  - Not just those undergoing change

Funnel Information to avoid overload and manage key messages



Integration Management Organization

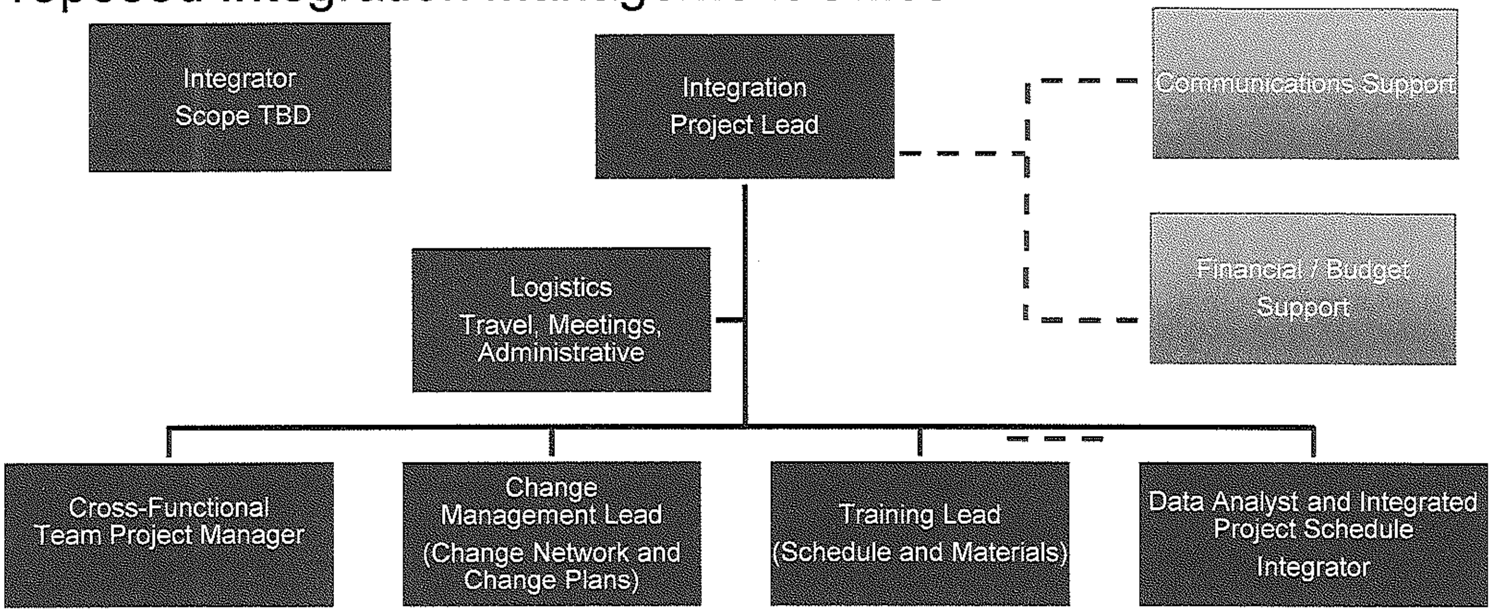
Review underway for Integration Support



Integration Management Office (IMO)

Resources: Internal and Integrator / Contractor Support

- Proposed Integration Management Office



- Functional teams need to determine resource requirements considering:
  - Time frames: now to “Day 1”, post close/pre SAP, after go live
  - Identify risks/staffing constraints
  - Use of integrator and impact to staffing needs

Functional Transition Team
Importance

Representatives chosen by leadership across service company departments and operations areas possessing the following:

- Leadership capability
- Organizationally savvy (understand companies "baselines" and understand how the companies will evolve to overall alignment)
- Ability to form early relationships/partnerships
- Ownership

Functional Transition Team

Overview and Expectations

- Collect baseline data of SCANA and participate in the kickoff, provide status updates at cross-functional meetings, and provide input/updates to communication review committee.
- Serve as liaisons for their respective departments.
- Lead SMEs in their area to address transition issues related to their departments and articulate business case for gaps.
- Provide guidance as needed on decisions that may impact their area(s).
- Identify and create task plans for their area. Manage and report updates on plans related to their specific areas.
- Collaborate and involve other areas where interdependencies arise.

The Integration Process

A sequential and staged approach to design and execution

Key Stages	Framework Development	Analysis	Design	Implementation Planning	Implementation
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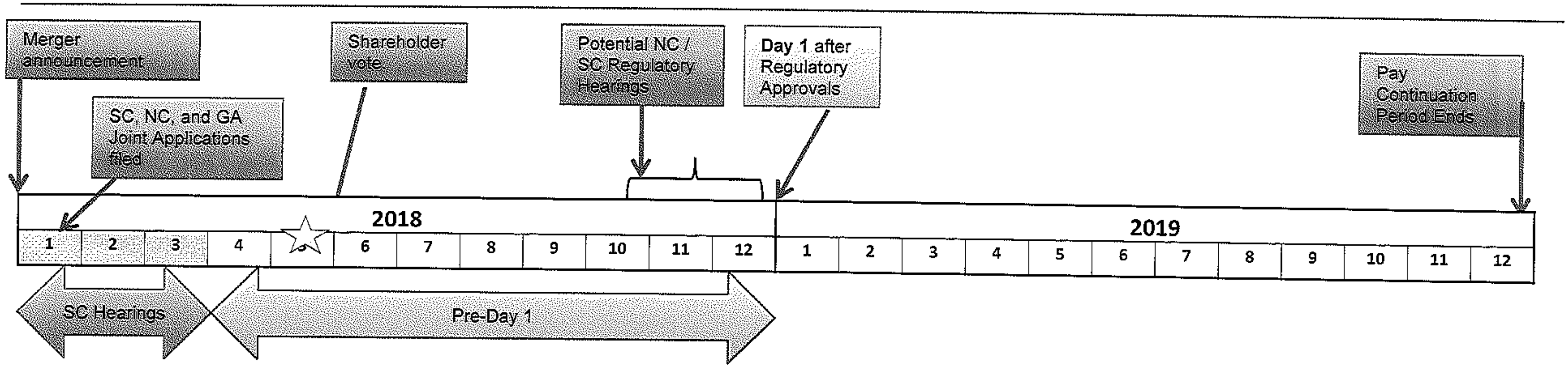

Now to Day 1

- Confirm transition leads and overall resource requirements during the phases of integration
- Kick off meeting with internal leads – Early April
- Kick off meeting with our SCANA Partners to begin baseline assessment (Early April)
- Solicit input from our peers on Integration approach and best practices
- Review potential "Integration support" for large scale integration
  - Invite firms to pitch services and support
  - Follow pitch sessions with planning session(s) to develop scope
  - Initiate formal procurement process

Transition Update

May 2018

Where we are now

Storm Management
- Pre Storm Notification
- Day 3 storm alert condition
  - Verification
  - Communication
  - Planning
  - Ensuring coverage
  - Assessing systems

Integration

Planning → **Analysis** → **Execution** → **Transition**

Planning
- Develop integration strategy and plan process

Analysis
- Conduct detailed integration analysis

Execution
- Define the future and implement day 1

Transition
- Unwind transition services and stand up new processes/org for day 2

What Dominion has done

- Conducted Questar lessons learned jointly with Questar team
  - Communication and coordination
  - Resource commitment
  - Magnitude of change
- Assessed need for integrator – currently out for RFP
  - Clean room – independent assessment
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  - Program management

What we've done

- Identified joint Integration mgmt office and SCANA transition team
- Defined rules of operation – antitrust, SEC, merger agreement
  - Held internal kickoff meeting 1/25
- Established weekly update meetings with subset of transition team
  - First weekly update summary was most clicked on Headlines article
  - Team has appreciated senior staff involvement in meetings
- Held bi-weekly/weekly communications meetings with Dominion

What else we've done

- Conducted one day HR process overview with Dominion
- Performed preliminary alignment of SCANA organization with Dominion organization
- Worked with Willis Towers Watson and Dominion on benefits comparison – scheduled to be provided to employees in q3
- Developed position tracking process to manage attrition, vacancies, etc.
- Established update cadence for employee FAQ on merger site
- Conducted joint diversity discussion around best practices and 2018 goals between Dominion diversity leadership and SCANA diversity steering committee

What else we've done

- Conducted one day IT infrastructure overview with Dominion
  - Focus on data center operations to determine options to 1401 Main
- Conducted multiple sessions between SCANA accounting and Dominion
  - Evaluating options for 3 day close requirement
  - Appear to primarily be process changes at this point
  - Will require separate revenue close and billing close for billing system
- Established process to grant Dominion integration team physical and network access to SCANA facilities and integration SharePoint site (will leverage SCANA managed site)

What else we've done

- Fought fires
  - Questions around communication with Dominion
  - Questions from Dominion about customers, advertising, etc
  - Questions about how contact centers respond to questions
  - Questions around existing projects
  - Questions around joint communications to customers
  - Communications reviews

What we plan to do

- Kick off in q2
- Organize by functional areas – initially support service focused
- Focus on best practices and synergies
  - Identify and implement early wins where appropriate
- Plan for Day 1 (close)
  - Ability to close books together in a timely manner
  - Ability for employees to look up other employees and view free/busy
  - Ability for employees to view job postings across organization
- Plan for Day 2 (integrated systems – anticipated 1/1/2020)
  - Conversion of SCANA Peoplesoft to Dominion SAP
  - Integration of organizations

Rules of engagement (highly condensed version!)

- Operate independently (planning for future is allowed)
- Limit exchanges of competitively sensitive information
- File all Written/recorded communications supporting merger with sec
- Keep each other reasonably informed and provide reasonable access
- Preserve confidentiality of any confidential information
- Not take any action that would prevent or delay merger
- Certain actions are restricted by merger agreement

When in doubt - ask

Dominion Energy, Inc.

Senior Management Planning Conference

May 14-15, 2018

Dominion Energy®

SCANA Integration

Draft – for discussion only

Considerations

- Merger agreement commitments
- Employee commitments
- Legislative process
- Regulatory process
- Questar lessons learned

Proposed Approach

- Integration model: Best practices over speed
- Benefits integration date
- Recommended organization and senior leadership structure for Day 1 and preliminarily as of 1/1/2021
- Integration into SAP on January 1, 2021
- Core businesses / operational excellence primary focus while leveraging economies of scale

Integration Team Focus

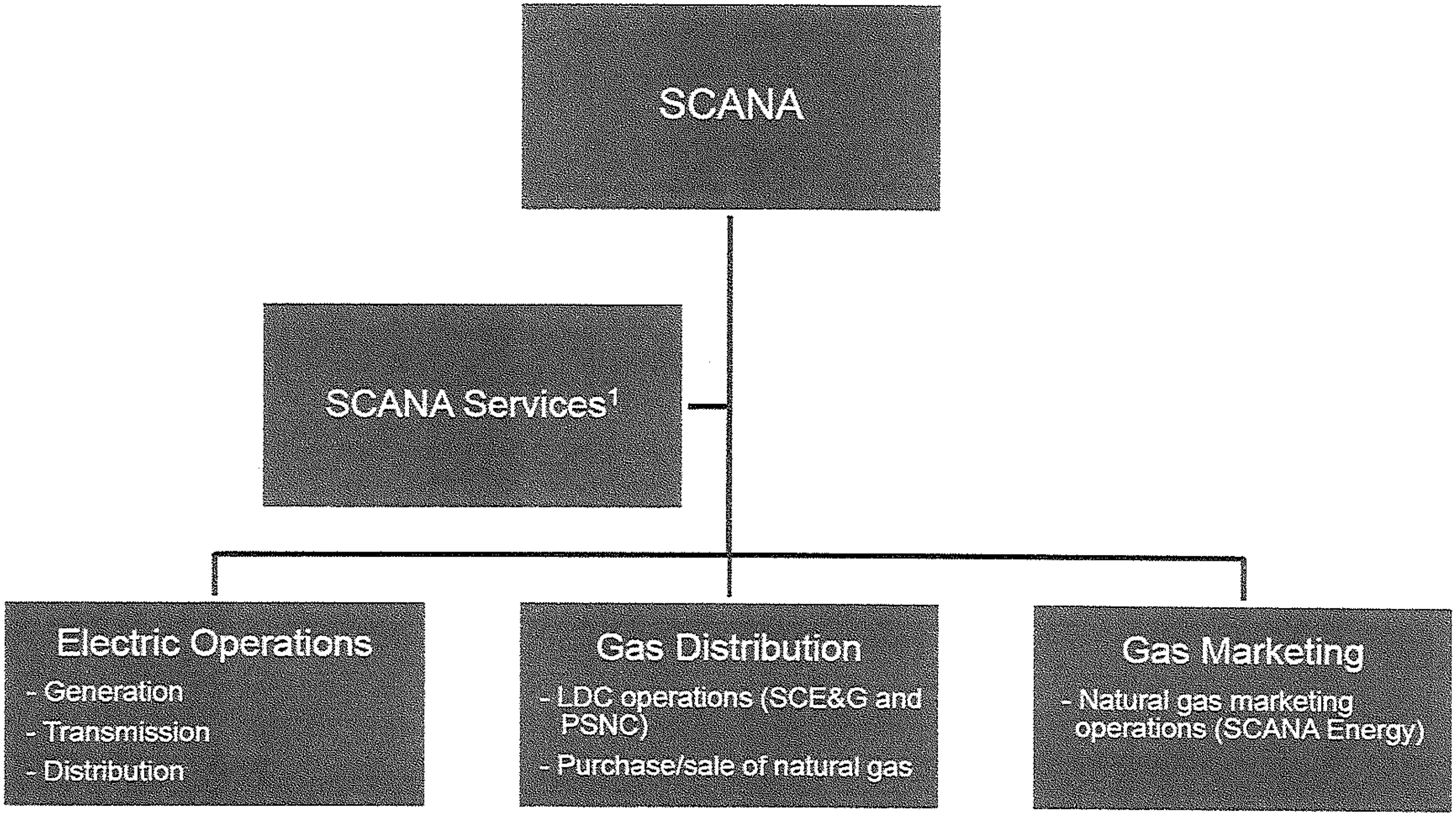
Day One Priorities

- Shared Values
- Consolidated financial reporting
- Compliance & safety alignment in terms of expectations vs. process
- Baseline employee experience
- Incorporation of corporate identity and brand plan

Longer Term:

- Development and execution of plans for future state
- Integration of Policies & Practices

SCANA Reporting Segments



[1] SCANA Services is not a separate segment for SCANA.

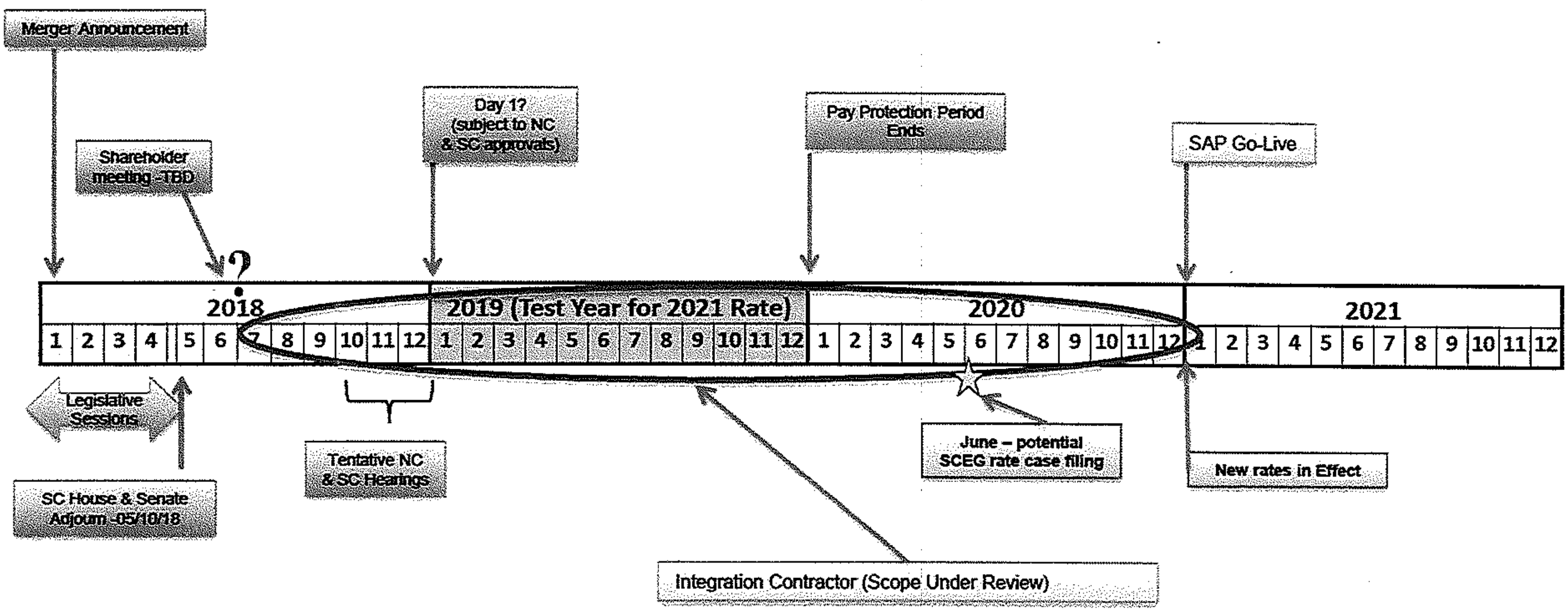
Potential – Reportable Operating and/or Organizational Segments

DRAFT – for discussion only

[redacted]

Integration Timeline

(DRAFT High Level – Estimated)



SCE&G electric rate schedule: assumes approval of merger condition to freeze retail electric base rates and the need to file for a rate increase beginning 2021 (PSNC follows a similar schedule)

SCE&G gas rate schedule: File every June 15 for the prior 12 month period ending March 31st, order issued by October 15th and rates are effective in November billing

Legislative Update & Other Impacts

- The legislature adjourned on May 10 without passing any bills related to SCANA.
- Two significant bills are in conference (S 954 and H 4375). They may be considered during two-day sessions in May 23-24 and June 13-15.
- The Sine Die Resolution reserves the right for the General Assembly to return for any matter related to VC Summers.
- Both pending bills and the pending budget bill set forth a schedule that would allow a hearing on the SCANA/DEI joint petition by November and would require an order by December 21. The Budget Bill must be approved by the end of June.
- Two additional members were elected to the PSC.
- Currently, the major difference between the House and Senate with regard to S 954 is the temporary reduction 13% vs 18%.
- The key legal issues regarding H 4375:
  - Creates a definition of prudency to be used in abandonment proceedings that raise significant due process issues (likely unconstitutional)
  - Modifies the weight given to stipulations between the utilities and ORS by the Commission
  - Transforms role of ORS staff from neutral evaluator to role of consumer counsel
- Next key dates are potential conference committee meetings and scheduled two day sessions in May and June…and the decision of SCANA about whether they will provide more direct rate relief to customers. (SCANA expected Q2 dividend would be paid on July 1).

Advertising and Polling

- "Stand by Me – Vets" TV running through May 10 in gas and electric territory
- "Stand by Me – Vets" branding campaign (radio, digital) running through May 25 in gas service territory
- Merger specific campaign (digital, radio) running through May 25 in electric service territory
- Latest polling conducted April 4-8

Executive Summary – Poll Data April 4-8

- This is the first poll conducted since Dominion Energy has been off the air from advertising.

- Among SCE&G electric customers, there are lower levels of awareness and support for the merger.

- SCE&G's image among electric customers is also more unfavorable.

- There are still low levels of awareness of Dominion Energy and SCANA Corp.

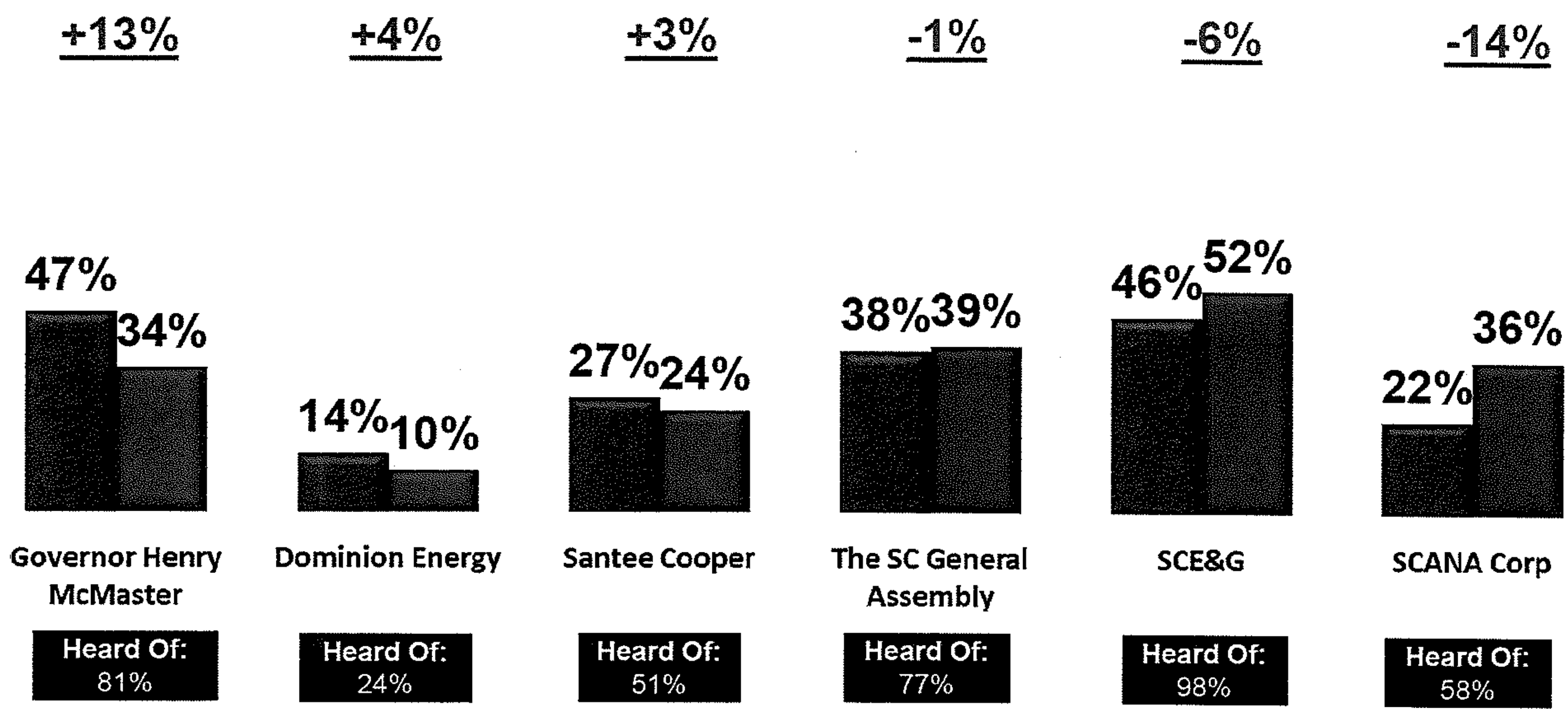
- There is overwhelming support for the General Assembly legislation. Talking about it being only a temporary solution is the most effective message against it.

- When positioning Dominion Energy's plan against the General Assembly legislation, side by side, the messaging that we tested makes voters and electric customers overwhelmingly side with Dominion Energy.

- But, at the end of the survey when asked which statement reflects their point of view about SCE&G, a majority of voters and electric customers still believe there should not be any deals made until electric customers are guaranteed they won't be charged at all for the cost of the failed nuclear plants. There is a desire for punishing the companies for this failure.

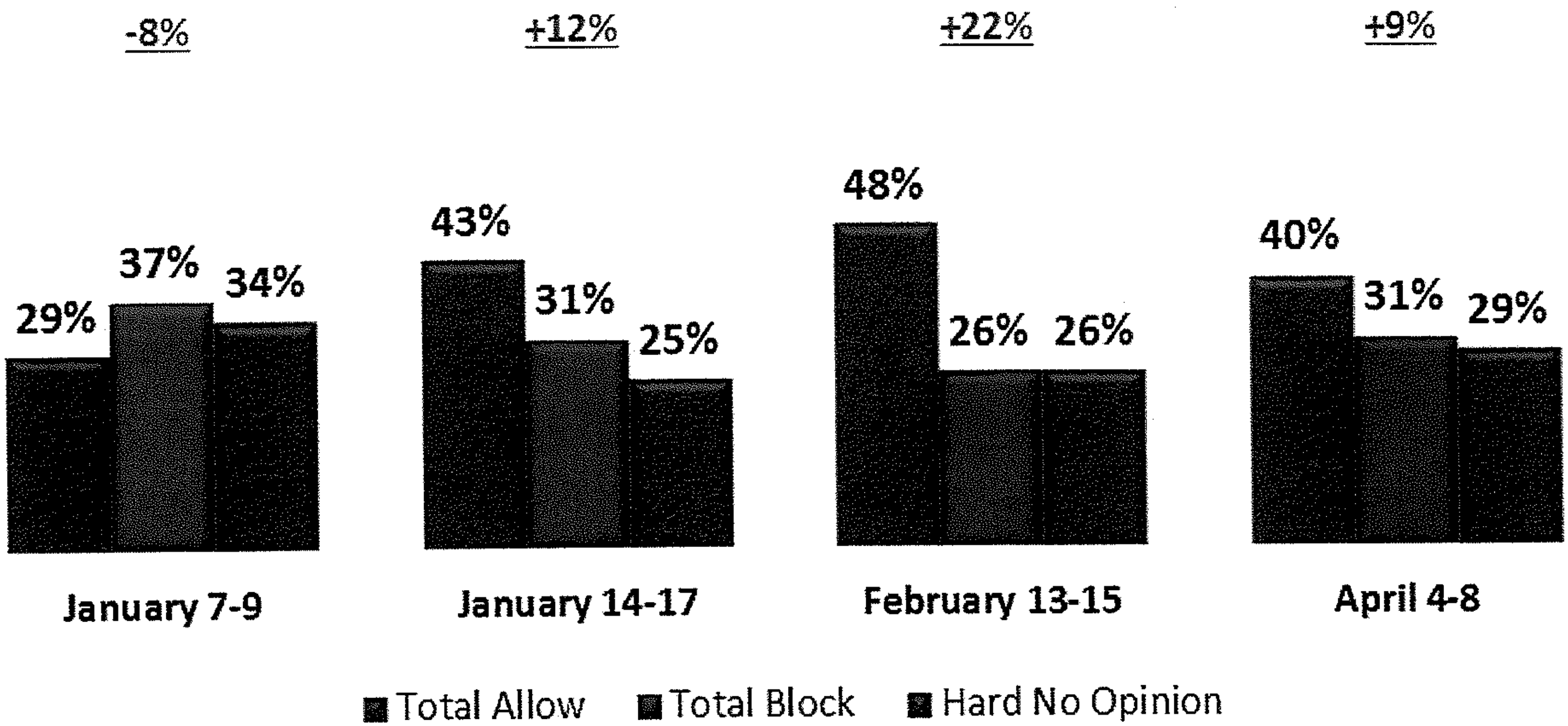
SCE&G Electric Customers' Opinion of SCE&G Continues to be More Unfavorable Over Time. In this April Survey, for the first time a majority of electric customers have an unfavorable view of the company

SCE&G Electric Customers – Ranked by Net Difference



Support for the Two Companies Combining Has Decreased and Opposition Has Increased Among Electric Customers Since February

Initial Allow/Block Companies Combining Into One Trend Among SCE&G Electric Customers



Now, do you think the South Carolina General Assembly and government regulators should ALLOW or BLOCK these companies from combining into one or do you not have an opinion one way or another?

Appendix

Commitments

- Merger Commitments
  - Maintain SCE&G headquarters in Cayce, SC
  - $1 M increase in charitable giving for 5 years
  - $1.3 B cash payment within 90 days to average customers
  - Minimum 7% bill reduction
  - Acquisition cost of natural-gas fired power station absorbed by shareholders
- Employee commitments
  - Pay continuation through 12/31/2019: Base pay and bonus plan target amounts at least equal to levels at close
  - Position eliminations: Individuals are eligible for base pay continuation through 12/31/2019 or the Dominion Energy Severance Plan, whichever is greater
  - Current active health and welfare benefit plans and policies will likely remain in place through 12/31/2019: Your years of service with SCANA will be recognized as service with Dominion Energy for policy purposes
  - Retirement Benefits through 12/31/2019: Pension, 401(k) and Retiree Medical
  - Employment Opportunities: accessible across the company at close
  - Retirement plan transition determined 3Q2018
  - Military full time employees will be granted up to 120 hours paid time off
- Legislative and Regulatory timing uncertainty

Media Favorability

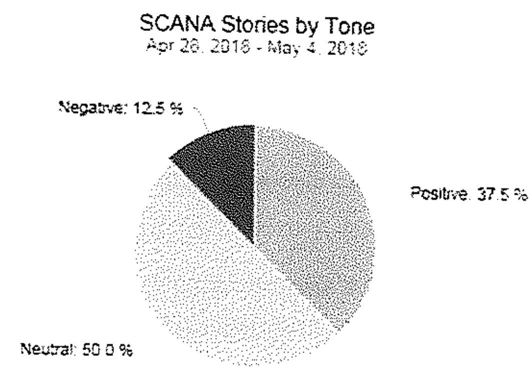
In the News:

- Post and Courier: Race Heats Up For Title To South Carolina's Most Valuable Public Company
- Post and Courier: SCANA Stock
- The State: SC Ratepayers, SCANA Stockholders Better Without Dominion

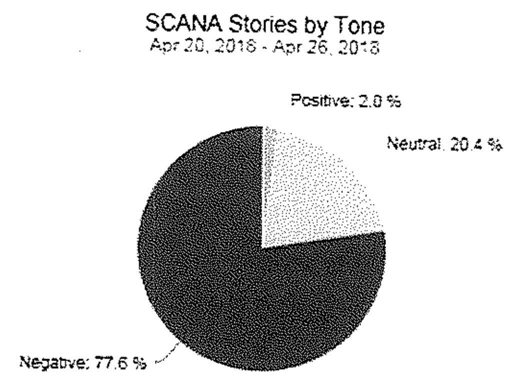
Letters of support:

- RTD: Dominion Energy 'No Flexibility' On SCAN Bid

W/E 5/11/18



W/E 5/4/18

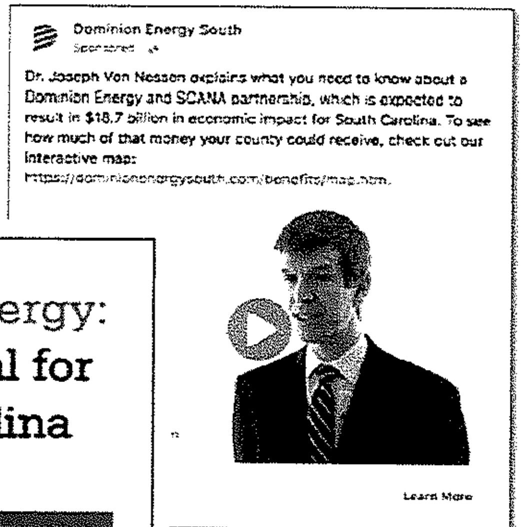


Digital Communications

Facebook, Twitter, BrighterEnergyFuture.com Digital Ads (non-traditional)

Website Traffic

Date Range	Sessions	Users	Pageviews	Avg. Session Duration
This Week	18,248	15,473	22,818	0:34
Since Launch	213,758	167,848	317,060	0:40
Daily Average	1,767	1,387	2,620	0:40



Digital Campaign Performance:

- **26,197,420** Impressions Delivered
- **161,463** Clicks on Ads
- **213,758** Website Sessions
- **1,676,586** Video Views
- **3,478** Total Facebook Page Likes

Highlights:

- Facebook campaigns, specific to the electric territory, that began running 4/17 have garnered 1.5M+ impressions, more than 27k clicks on ads and 11,200 website visits.
- We also have Community and Vets content running on Facebook in all service territories with nearly 3M impressions and 25k clicks.

Coming Up:

- Paid campaigns ends May 10
- S.C. team exploring customer calculator for website, but no update on when or if that will go live

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-7:

Review the response to ORS 4-14 and provide an update to reflect the present status.

RESPONSE 7-7:

See Response ORS 7-6. As indicated in Responses ORS 4-14 and ORS 7-6, planning for integration with Dominion Energy continues in the very early stages. Formal kick off meetings between SCANA and Dominion Energy have not been scheduled at this time and as such there are no other presentations, studies, analysis, or status/progress reports on the integration efforts to date. As material components of the integration plan are finalized, updated information will be provided.

RESPONSIBLE PERSON: Karla Haislip (Dominion Energy) and Joanna Greene (SCANA/SCE&G)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
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DOCKET NO. 2017-207-E (8th Continuing AIR)
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DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-8:

Provide a schedule in an Excel spreadsheet showing the actual non-fuel or non-gas O&M expenses by FERC account for each Dominion electric utility and gas Local Distribution Company acquired by Dominion starting the year prior to Dominion's acquisition of the utility and continuing for the five years after the acquisition. This request includes, but is not limited to, Dominion East Ohio, Dominion Hope, and Questar Gas.

RESPONSE 7-8:

Please see DE Attachment ORS 7-8 on the enclosed CD for The East Ohio Gas Company, doing business as Dominion Energy Ohio; Hope Gas, Inc., doing business as Dominion Energy West Virginia; and Questar Gas Company doing business as Dominion Energy Utah, Dominion Energy Wyoming, and Dominion Energy Idaho. There are no other acquired local distribution companies currently part of Dominion Energy.

RESPONSIBLE PERSON: Joshua Blakeney

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-9:

Provide a schedule in an Excel spreadsheet showing the charges from SCANA Services, Inc. to SCE&G by FERC account for 2016 and 2017. Separate the 900 series account expenses into electric and gas.

RESPONSE 7-9:
Please see attached spreadsheet.

RESPONSIBLE PERSON: Lawton Blackstone

SCANA Services Charges to SCE&G by FERC Account
For Calendar Year 2017
Response to ORS AIR 7-9

REPORTING BUSINESS UNIT	FERC Account	LINE OF BUSINESS	Direct Billed	Allocated	Total Billed
SCEG	1070		41,702,745.32	2,702,046.86	44,404,792.18
SCEG	1080		2,230,068.78	-	2,230,068.78
SCEG	1180		12,829,389.40	431,488.31	13,260,877.71
SCEG	1190		59,796.77	-	59,796.77
SCEG	1210		2,225,493.14	-	2,225,493.14
SCEG	1540		9,162.64	-	9,162.64
SCEG	1630		553,793.81	-	553,793.81
SCEG	1822		3,104.25	-	3,104.25
SCEG	1823		9,274,136.75	-	9,274,136.75
SCEG	1830		45,332.59	-	45,332.59
SCEG	1832		261,348.26	-	261,348.26
SCEG	1840		2,297,460.58	1,280,199.85	3,577,660.43
SCEG	1860		1,629,287.34	66,203.81	1,695,491.15
SCEG	2270		(1,231,124.28)	-	(1,231,124.28)
SCEG	2430		5,616.66	-	5,616.66
SCEG	4081		1,910,779.22	5,949,034.95	7,859,814.17
SCEG	4082		301,460.87	73,710.94	375,171.81
SCEG	4111		-	144,500.00	144,500.00
SCEG	4112		-	2,600.00	2,600.00
SCEG	4140		-	12,523,072.64	12,523,072.64
SCEG	4160		3,696,075.79	288,683.99	3,984,759.78
SCEG	4171		686,856.17	246,838.62	933,694.79
SCEG	4210			74,310.39	74,310.39
SCEG	4261		1,627,286.93	416,654.29	2,043,941.22
SCEG	4263		350.58	-	350.58
SCEG	4264		1,713,836.88	761,762.63	2,475,599.51
SCEG	4265		6,627,493.95	2,709,096.36	9,336,590.31
SCEG	4300		-	6,588,410.71	6,588,410.71
SCEG	4320		-	(14,250.54)	(14,250.54)
SCEG	5000		10,035.92	-	10,035.92
SCEG	5010		745,068.63	-	745,068.63
SCEG	5020		10.00	-	10.00
SCEG	5060		1,193,213.13	-	1,193,213.13
SCEG	5110		79,438.36	-	79,438.36
SCEG	5120		53,430.78	-	53,430.78
SCEG	5130		22.50	-	22.50
SCEG	5140		18,941.49	-	18,941.49
SCEG	5170		116,059.31	-	116,059.31
SCEG	5190		106,099.96	-	106,099.96
SCEG	5200		351,723.99	-	351,723.99
SCEG	5240		7,377,559.22	-	7,377,559.22
SCEG	5290		633,727.32	-	633,727.32
SCEG	5300		1,275.24	-	1,275.24
SCEG	5310		-	-	-
SCEG	5320		1,778,727.47	-	1,778,727.47
SCEG	5350		3,153.20	-	3,153.20
SCEG	5370		20,666.26	-	20,666.26
SCEG	5380		1,648.47	-	1,648.47
SCEG	5390		186,793.00	-	186,793.00
SCEG	5430		108,997.94	-	108,997.94
SCEG	5440		7,271.81	-	7,271.81
SCEG	5450		-	-	-

SCEG	5460	11,021.48	-	11,021.48
SCEG	5480	1,554.21	-	1,554.21
SCEG	5490	147,733.43	-	147,733.43
SCEG	5510	275.00	-	275.00
SCEG	5520	18,129.80	-	18,129.80
SCEG	5530	19,433.93	-	19,433.93
SCEG	5540	45,343.44	-	45,343.44
SCEG	5560	295,992.38	-	295,992.38
SCEG	5600	16,818.15	-	16,818.15
SCEG	5611	6,988.07	-	6,988.07
SCEG	5612	43,875.46	-	43,875.46
SCEG	5617	2,664.90	-	2,664.90
SCEG	5620	2,684,864.07	-	2,684,864.07
SCEG	5630	21,029.41	-	21,029.41
SCEG	5660	422,469.20	-	422,469.20
SCEG	5680	43,215.79	-	43,215.79
SCEG	5690	35,330.32	-	35,330.32
SCEG	5700	313,027.89	-	313,027.89
SCEG	5710	29,176.78	-	29,176.78
SCEG	5730	164,151.61	-	164,151.61
SCEG	5800	87,103.52	-	87,103.52
SCEG	5810	1,417.17	-	1,417.17
SCEG	5820	175,626.67	-	175,626.67
SCEG	5830	8,499.86	-	8,499.86
SCEG	5840	12.50	-	12.50
SCEG	5850	285.00	-	285.00
SCEG	5860	35,445.83	-	35,445.83
SCEG	5880	3,539,111.10	-	3,539,111.10
SCEG	5890	241,643.15	-	241,643.15
SCEG	5900	1,886.30	-	1,886.30
SCEG	5920	165,563.44	-	165,563.44
SCEG	5930	296,648.12	-	296,648.12
SCEG	5940	58,139.95	-	58,139.95
SCEG	5960	19,058.49	-	19,058.49
SCEG	5970	108,931.39	-	108,931.39
SCEG	5980	3,255.77	-	3,255.77
SCEG	7350	358,098.51	-	358,098.51
SCEG	8030	-	-	-
SCEG	8400	61,298.10	2,000.75	63,298.85
SCEG	8410	(9,251.72)	2,340.61	(6,911.11)
SCEG	8432	17,248.72	-	17,248.72
SCEG	8439	22,144.94	-	22,144.94
SCEG	8610	-	755.88	755.88
SCEG	8670	-	227.16	227.16
SCEG	8700	504,178.97	263,582.54	767,761.51
SCEG	8710	8,456.64	-	8,456.64
SCEG	8740	464,685.66	440,428.32	905,113.98
SCEG	8750	12,973.03	-	12,973.03
SCEG	8760	416,027.39	-	416,027.39
SCEG	8780	5,829.69	-	5,829.69
SCEG	8790	3,088.24	-	3,088.24
SCEG	8800	473,847.69	2,801.75	476,649.44
SCEG	8810	233,292.18	-	233,292.18
SCEG	8850	5,746.94	4,187.28	9,934.22
SCEG	8870	506,692.60	5,841.36	512,533.96
SCEG	8900	217.65	-	217.65
SCEG	8920	386,680.32	-	386,680.32
SCEG	8930	134,684.66	35,275.87	169,960.53

SCEG	8940		429.17	-	429.17
SCEG	9010	ELECTRIC	555,004.19	6,598.75	561,602.94
SCEG	9010	GAS	53,465.89	797.69	54,263.58
SCEG	9020	ELECTRIC	566,630.40	145,918.44	712,548.84
SCEG	9020	GAS	65,148.09	13,666.18	78,814.27
SCEG	9030	ELECTRIC	26,286,028.45	2,068,994.56	28,355,023.01
SCEG	9030	GAS	3,729,852.07	241,523.40	3,971,375.47
SCEG	9040	ELECTRIC	(662.33)	-	(662.33)
SCEG	9040	GAS	(245.83)	-	(245.83)
SCEG	9050	ELECTRIC	2,571,238.71	(20,414.68)	2,550,824.03
SCEG	9050	GAS	527,319.56	(1,911.72)	525,407.84
SCEG	9070	GAS	824.13	-	824.13
SCEG	9080	ELECTRIC	199,889.56	-	199,889.56
SCEG	9080	GAS	26,668.20	-	26,668.20
SCEG	9100	ELECTRIC	271.73	(439.33)	(167.60)
SCEG	9100	GAS	175,749.97	262.92	176,012.89
SCEG	9110	GAS	1,431.65	-	1,431.65
SCEG	9120	ELECTRIC	35,167.48	(570.07)	34,597.41
SCEG	9120	GAS	435,310.97	130.34	435,441.31
SCEG	9130	ELECTRIC	33.56	208.39	241.95
SCEG	9130	GAS	3.15	(3,290.49)	(3,287.34)
SCEG	9160	ELECTRIC	63.80	337,122.41	337,186.21
SCEG	9160	GAS	262,101.74	176,532.81	438,634.55
SCEG	9200	ELECTRIC	11,182,746.71	12,040,570.04	23,223,316.75
SCEG	9200	GAS	2,821,530.85	1,711,852.98	4,533,383.83
SCEG	9210	ELECTRIC	7,911,536.06	5,830,766.34	13,742,302.40
SCEG	9210	GAS	1,152,691.75	852,379.60	2,005,071.35
SCEG	9230	ELECTRIC	11,047,394.71	5,306,045.50	16,353,440.21
SCEG	9230	GAS	878,124.13	570,668.83	1,448,792.96
SCEG	9240	ELECTRIC	(454,942.92)	379,383.35	(75,559.57)
SCEG	9240	GAS	11,710.02	32,065.93	43,775.95
SCEG	9250	ELECTRIC	5,610,660.85	148,577.33	5,759,238.18
SCEG	9250	GAS	1,178,996.78	17,875.76	1,196,872.54
SCEG	9260	ELECTRIC	6,754,220.42	6,527,147.92	13,281,368.34
SCEG	9260	GAS	1,665,340.99	1,262,472.27	2,927,813.26
SCEG	9280	ELECTRIC	1,018,033.51	(400.49)	1,017,633.02
SCEG	9280	GAS	274,021.76	(206.27)	273,815.49
SCEG	9301	ELECTRIC	20,420.40	(559.83)	19,860.57
SCEG	9301	GAS	7,579.60	(280.81)	7,298.79
SCEG	9302	ELECTRIC	1,700,197.94	2,089,637.03	3,789,834.97
SCEG	9302	GAS	488,282.66	190,726.56	679,009.22
SCEG	9310	ELECTRIC	3,624,040.72	1,541,787.18	5,165,827.90
SCEG	9310	GAS	524,973.84	665,800.29	1,190,774.13
SCEG	9320	ELECTRIC	553.32	51.68	605.00
SCEG	9320	GAS	5.39	25.92	31.31
SCEG	9350	ELECTRIC	4,050,267.97	2,282,275.22	6,332,543.19
SCEG	9350	GAS	1,215,698.15	351,459.16	1,567,157.31
			212,101,090.11	**79,767,056.42**	**291,868,146.53**

SCANA Services Charges to SCE&G by FERC Account
For Calendar Year 2016
Response to ORS AIR 7-9

REPORTING BUSINESS UNIT	FERC Account	LINE OF BUSINESS	Direct Billed	Allocated	Total Billed
SCEG	1070		36,963,096.24	2,827,349.82	39,790,446.06
SCEG	1080		2,692,063.02	-	2,692,063.02
SCEG	1180		21,280,609.33	412,488.91	21,693,098.24
SCEG	1190		172,957.10	-	172,957.10
SCEG	1210		1,169,534.23	-	1,169,534.23
SCEG	1540		11,540.30	-	11,540.30
SCEG	1630		605,446.76	-	605,446.76
SCEG	1822		3,530.35	-	3,530.35
SCEG	1823		9,112,578.82	-	9,112,578.82
SCEG	1830		22,016.70	-	22,016.70
SCEG	1832		337,494.35	-	337,494.35
SCEG	1840		1,885,831.27	1,190,223.13	3,076,054.40
SCEG	1860		2,217,437.17	69,797.10	2,287,234.27
SCEG	2270		(580,861.79)	-	(580,861.79)
SCEG	2430		(305,736.93)	-	(305,736.93)
SCEG	4081		3,767,859.27	5,742,156.47	9,510,015.74
SCEG	4082		255,458.51	76,977.74	332,436.25
SCEG	4101		-	-	-
SCEG	4140		1,034,471.87	11,253,267.33	12,287,739.20
SCEG	4160		4,366,870.29	348,371.36	4,715,241.65
SCEG	4171		808,869.60	265,559.99	1,074,429.59
SCEG	4210		-	74,329.38	74,329.38
SCEG	4261		3,038,674.40	153,166.75	3,191,841.15
SCEG	4264		927,008.63	592,098.32	1,519,106.95
SCEG	4265		4,149,027.65	2,827,358.18	6,976,385.83
SCEG	4300		-	6,296,982.60	6,296,982.60
SCEG	4310		9,538.93	-	9,538.93
SCEG	4320		-	(6,802.34)	(6,802.34)
SCEG	5000		18,195.31	-	18,195.31
SCEG	5010		732,242.57	-	732,242.57
SCEG	5020		25.00	-	25.00
SCEG	5060		624,471.40	-	624,471.40
SCEG	5110		213,072.02	-	213,072.02
SCEG	5120		124,574.20	-	124,574.20
SCEG	5130		715.00	-	715.00
SCEG	5140		22,379.05	-	22,379.05
SCEG	5170		108,511.08	-	108,511.08
SCEG	5190		58,246.43	-	58,246.43
SCEG	5200		338,026.07	-	338,026.07
SCEG	5240		5,047,804.44	-	5,047,804.44
SCEG	5280		686.97	-	686.97
SCEG	5290		501,225.54	-	501,225.54
SCEG	5300		25,054.11	-	25,054.11
SCEG	5310		-	-	-
SCEG	5320		1,478,203.32	-	1,478,203.32
SCEG	5350		4,555.84	-	4,555.84
SCEG	5370		23,063.55	-	23,063.55
SCEG	5380		909.09	-	909.09
SCEG	5390		169,847.78	-	169,847.78
SCEG	5430		43,227.72	-	43,227.72
SCEG	5440		50,551.57	-	50,551.57
SCEG	5450		3,281.54	-	3,281.54
SCEG	5460		12,827.02	-	12,827.02
SCEG	5480		357.23	-	357.23
SCEG	5490		170,368.04	-	170,368.04
SCEG	5510		2,888.91	-	2,888.91
SCEG	5520		1,920.61	-	1,920.61
SCEG	5530		19,347.24	-	19,347.24

SCEG	5560		289,645.36	-	289,645.36
SCEG	5600		11,583.21	-	11,583.21
SCEG	5611		6,748.71	-	6,748.71
SCEG	5612		42,999.82	-	42,999.82
SCEG	5617		1,779.39	-	1,779.39
SCEG	5620		189,193.45	-	189,193.45
SCEG	5630		1,395.66	-	1,395.66
SCEG	5660		345,220.80	-	345,220.80
SCEG	5680		23,685.70	-	23,685.70
SCEG	5690		27,497.78	-	27,497.78
SCEG	5692		96.00	-	96.00
SCEG	5700		232,750.39	-	232,750.39
SCEG	5710		94,709.94	-	94,709.94
SCEG	5730		177,760.82	-	177,760.82
SCEG	5800		174,267.74	-	174,267.74
SCEG	5810		1,382.74	-	1,382.74
SCEG	5820		142,844.84	-	142,844.84
SCEG	5830		10,714.27	-	10,714.27
SCEG	5850		95.00	-	95.00
SCEG	5860		14,396.77	-	14,396.77
SCEG	5880		1,517,037.67	-	1,517,037.67
SCEG	5890		237,849.12	-	237,849.12
SCEG	5900		1,643.11	-	1,643.11
SCEG	5910		2,548.40	-	2,548.40
SCEG	5920		162,704.05	-	162,704.05
SCEG	5930		1,307,556.37	-	1,307,556.37
SCEG	5940		51,570.37	-	51,570.37
SCEG	5950		323.38	-	323.38
SCEG	5960		9,067.41	-	9,067.41
SCEG	5970		66,726.32	-	66,726.32
SCEG	5980		6,386.00	-	6,386.00
SCEG	7350		467,539.45	-	467,539.45
SCEG	8400		69,299.22	2,584.99	71,884.21
SCEG	8410		53,046.51	1,530.96	54,577.47
SCEG	8432		18,998.92	-	18,998.92
SCEG	8439		23,172.85	-	23,172.85
SCEG	8510		-	235.47	235.47
SCEG	8610		-	6,533.89	6,533.89
SCEG	8700		452,376.01	252,372.46	704,748.47
SCEG	8710		7,762.44	-	7,762.44
SCEG	8740		498,148.68	415,692.57	913,841.25
SCEG	8750		43,163.42	393.38	43,556.80
SCEG	8760		102,897.14	552.06	103,449.20
SCEG	8780		15,923.39	409.92	16,333.31
SCEG	8790		15,425.70	-	15,425.70
SCEG	8800		371,377.01	3,561.17	374,938.18
SCEG	8810		225,903.54	-	225,903.54
SCEG	8850		873.01	733.73	1,606.74
SCEG	8870		536,963.70	-	536,963.70
SCEG	8900		630.95	-	630.95
SCEG	8920		2,387.44	-	2,387.44
SCEG	8930		120,238.77	52,703.35	172,942.12
SCEG	8940		735.72	-	735.72
SCEG	9010	ELECTRIC	1,090,272.86	1,419.62	1,091,692.48
SCEG	9010	GAS	130,662.01	225.61	130,887.62
SCEG	9020	ELECTRIC	527,448.77	152,400.22	679,848.99
SCEG	9020	GAS	68,040.90	14,331.21	82,372.11
SCEG	9030	ELECTRIC	27,849,553.05	1,416,526.54	29,266,079.59
SCEG	9030	GAS	4,084,735.93	132,468.15	4,217,204.08
SCEG	9040	ELECTRIC	(441.07)	-	(441.07)
SCEG	9040	GAS	(161.15)	-	(161.15)
SCEG	9050	ELECTRIC	2,581,470.27	86,261.86	2,667,732.13
SCEG	9050	GAS	508,425.75	8,111.80	516,537.55
SCEG	9070	ELECTRIC	342.47	-	342.47

SCEG	9070	GAS	1,537.49	-	1,537.49
SCEG	9080	ELECTRIC	199,785.85	-	199,785.85
SCEG	9080	GAS	34,365.20	497.37	34,862.57
SCEG	9100	ELECTRIC	31,323.16	57,907.81	89,230.97
SCEG	9100	GAS	281,324.85	8,258.91	289,583.76
SCEG	9110	GAS	7,663.64	-	7,663.64
SCEG	9120	ELECTRIC	35,924.56	4,164.46	40,089.02
SCEG	9120	GAS	413,441.80	2,320.61	415,762.41
SCEG	9130	ELECTRIC	559.27	1,312.93	1,872.20
SCEG	9130	GAS	82.54	4,661.68	4,744.22
SCEG	9160	ELECTRIC	44.05	227,887.96	227,932.01
SCEG	9160	GAS	231,130.02	107,781.16	338,911.18
SCEG	9200	ELECTRIC	36,191,257.54	12,199,224.74	48,390,482.28
SCEG	9200	GAS	6,826,447.53	1,606,814.75	8,433,262.28
SCEG	9210	ELECTRIC	12,095,341.86	6,368,186.46	18,463,528.32
SCEG	9210	GAS	1,336,315.20	761,561.92	2,097,877.12
SCEG	9230	ELECTRIC	10,076,057.98	4,652,837.95	14,728,895.93
SCEG	9230	GAS	753,565.11	447,356.00	1,200,921.11
SCEG	9240	ELECTRIC	(417,593.20)	352,593.91	(64,999.29)
SCEG	9240	GAS	11,653.30	30,119.83	41,773.13
SCEG	9250	ELECTRIC	3,556,000.23	358,221.06	3,914,221.29
SCEG	9250	GAS	455,967.45	34,159.46	490,126.91
SCEG	9260	ELECTRIC	7,392,446.71	6,572,920.86	13,965,367.57
SCEG	9260	GAS	1,638,645.04	1,129,080.12	2,767,725.16
SCEG	9280	ELECTRIC	79,660.51	412.68	80,073.19
SCEG	9280	GAS	273,648.33	204.24	273,852.57
SCEG	9301	ELECTRIC	20,141.00	558.85	20,699.85
SCEG	9301	GAS	7,359.00	276.58	7,635.58
SCEG	9302	ELECTRIC	2,323,921.06	2,130,217.35	4,454,138.41
SCEG	9302	GAS	338,333.44	195,380.08	533,713.52
SCEG	9310	ELECTRIC	3,616,348.78	1,504,634.45	5,120,983.23
SCEG	9310	GAS	434,937.35	690,920.59	1,125,857.94
SCEG	9320	ELECTRIC	659.87	-	659.87
SCEG	9320	GAS	56.40	-	56.40
SCEG	9350	ELECTRIC	4,919,586.76	2,026,500.28	6,946,087.04
SCEG	9350	GAS	1,180,891.03	281,177.26	1,462,068.29
			243,110,119.68	**76,430,526.02**	**319,540,645.70**

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-10:

Question 6-22 asked SCE&G to extend the schedule through the most recent month for which actual amounts are available, but SCE&G extended the schedule only through November 2017. Update the response to ORS 6-22 with actual information through May 2018 or explain why this information is not available. Update with additional months as actual information become available.

RESPONSE 7-10:

Please see the attached.

RESPONSIBLE PERSON: Kevin Kochems

South Carolina Electric & Gas Company
Office of Regulatory Staff's Continuing
Audit Information Request
Docket No. 2017-207-E (5th Continuing AIR)
Docket No. 2017-305-E (4th Continuing AIR)
Docket No. 2017-370-E (4th Continuing AIR)

Response No. 7-10

VCS 2 and 3 CWIP

($000)

	PTD Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15
WO 17 - NND only*												
Direct Expenditures	$2,633,730	$ 43,764	$ 63,248	$ 37,876	$ 45,888	$ 32,123	$ 32,511	$ 38,452	$ 30,218	$ 29,265	$ 35,508	$ 52,144
AFUDC	$ 108,641	$ 854	$ 941	$ 1,229	$ 1,515	$ 1,654	$ 1,845	$ 2,038	$ 2,195	$ 2,374	$ 2,355	$ 437
CWIP for Period	$2,742,371	$ 44,617	$ 64,189	$ 39,105	$ 47,403	$ 33,777	$ 34,355	$ 40,491	$ 32,413	$ 31,640	$ 37,863	$ 52,582
Balance to Date	$2,742,371	$2,786,988	$2,851,177	$2,890,282	$2,937,685	$2,971,462	$3,005,817	$3,046,308	$3,078,721	$3,110,361	$3,148,224	$3,200,806
Transmission WO's												
Direct Expenditures	$ 188,996	$ 2,738	$ 4,473	$ 3,170	$ 3,665	$ 3,153	$ 5,155	$ 4,676	$ 4,452	$ 5,357	$ 4,876	$ 2,924
AFUDC	$ 10,225	$ 224	$ 240	$ 261	$ 279	$ 298	$ 320	$ 343	$ 369	$ 393	$ 412	$ 164
CWIP for Period	$ 199,221	$ 2,961	$ 4,712	$ 3,431	$ 3,945	$ 3,451	$ 5,475	$ 5,019	$ 4,821	$ 5,751	$ 5,288	$ 3,088
Balance to Date	$ 199,221	$ 202,182	$ 206,895	$ 210,326	$ 214,271	$ 217,721	$ 223,196	$ 228,216	$ 233,037	$ 238,787	$ 244,076	$ 247,163
Total BLRA												
Direct Expenditures	$2,822,725	$ 46,501	$ 67,720	$ 41,046	$ 49,553	$ 35,276	$ 37,666	$ 43,129	$ 34,670	$ 34,623	$ 40,384	$ 55,068
AFUDC	$ 118,867	$ 1,077	$ 1,181	$ 1,491	$ 1,795	$ 1,951	$ 2,164	$ 2,381	$ 2,564	$ 2,768	$ 2,767	$ 601
CWIP for Period	$2,941,592	$ 47,579	$ 68,901	$ 42,537	$ 51,348	$ 37,228	$ 39,830	$ 45,510	$ 37,235	$ 37,390	$ 43,151	$ 55,669
Balance to Date	$2,941,592	$2,989,171	$3,058,072	$3,100,608	$3,151,956	$3,189,183	$3,229,013	$3,274,524	$3,311,758	$3,349,149	$3,392,300	$3,447,969

	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16
WO 17 - NND only*												
Direct Expenditures	$ 163,799	$ 55,918	$ 40,921	$ 32,911	$ 52,738	$ 48,956	$ 44,315	$ 50,810	$ 46,449	$ 170,371	$ 83,374	$ 109,336
AFUDC	$ 1,276	$ 567	$ 1,058	$ 1,334	$ 2,031	$ 2,480	$ 2,944	$ 3,479	$ 4,014	$ 619	$ 2,656	$ 3,660
CWIP for Period	$ 165,075	$ 56,486	$ 41,979	$ 34,246	$ 54,769	$ 51,436	$ 47,259	$ 54,289	$ 50,463	$ 170,990	$ 86,030	$ 112,996
Balance to Date	$3,365,881	$3,422,366	$3,464,346	$3,498,591	$3,553,360	$3,604,797	$3,652,055	$3,706,344	$3,756,807	$3,927,798	$4,013,828	$4,126,824
Transmission WO's												
Direct Expenditures	$ 6,943	$ 2,092	$ 3,516	$ 3,451	$ 5,574	$ 2,697	$ 2,817	$ 5,694	$ 2,362	$ 2,600	$ 1,281	$ 2,435
AFUDC	$ 186	$ 216	$ 231	$ 249	$ 269	$ 290	$ 306	$ 325	$ 344	$ 358	$ 368	$ 377
CWIP for Period	$ 7,128	$ 2,308	$ 3,747	$ 3,699	$ 5,844	$ 2,987	$ 3,123	$ 6,019	$ 2,706	$ 2,958	$ 1,649	$ 2,812
Balance to Date	$ 254,292	$ 256,600	$ 260,347	$ 264,046	$ 269,889	$ 272,877	$ 276,000	$ 282,019	$ 284,725	$ 287,683	$ 289,332	$ 292,144
Total BLRA												
Direct Expenditures	$ 170,741	$ 58,010	$ 44,437	$ 36,362	$ 58,312	$ 51,653	$ 47,132	$ 56,504	$ 48,811	$ 172,971	$ 84,656	$ 111,771
AFUDC	$ 1,462	$ 783	$ 1,289	$ 1,583	$ 2,300	$ 2,770	$ 3,250	$ 3,804	$ 4,357	$ 977	$ 3,024	$ 4,037
CWIP for Period	$ 172,203	$ 58,794	$ 45,726	$ 37,945	$ 60,613	$ 54,423	$ 50,382	$ 60,308	$ 53,168	$ 173,948	$ 87,679	$ 115,808
Balance to Date	$3,620,172	$3,678,966	$3,724,692	$3,762,637	$3,823,250	$3,877,673	$3,928,055	$3,988,364	$4,041,532	$4,215,480	$4,303,160	$4,418,968

South Carolina Electric & Gas Company
Office of Regulatory Staff's Continuing
Audit Information Request
Docket No. 2017-207-E (5th Continuing AIR)
Docket No. 2017-305-E (4th Continuing AIR)
Docket No. 2017-370-E (4th Continuing AIR)

Response No. 7-10

VCS 2 and 3 CWIP

($000)

PTD	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17
WO 17 - NND only*												
Direct Expenditures	$ 79,187	$ 48,702	$ 51,083	$ 15,306	$ 86,861	$ 82,031	$ 110,707	$ 70,203	$ 18,140	$ 20,965	$ -	$ -
AFUDC	$ 2,523	$ 3,082	$ 3,247	$ 3,602	$ 4,105	$ 4,511	$ 1,250	$ 4,569	$ -	$ (6,713)	$ -	$ -
CWIP for Period	$ 81,710	$ 51,784	$ 54,329	$ 18,907	$ 90,966	$ 86,542	$ 111,958	$ 74,772	$ 18,140	$ 14,252	$ -	$ -
Balance to Date	$4,208,534	$4,260,318	$4,314,647	$4,333,555	$4,424,521	$4,511,063	$4,623,020	$4,697,792	$4,715,932	$4,730,184	$4,730,184	$4,730,184
Transmission WO's												
Direct Expenditures	$ 2,473	$ 1,555	$ 1,795	$ 1,565	$ 1,604	$ 2,722	$ 1,392	$ 2,797	$ 4,959	$ 1,430	$ 2,813	$ 5,706
AFUDC	$ 118	$ 133	$ 142	$ 151	$ 159	$ 169	$ 180	$ 190	$ (358)	$ 181	$ 86	$ 57
CWIP for Period	$ 2,591	$ 1,688	$ 1,937	$ 1,715	$ 1,763	$ 2,891	$ 1,572	$ 2,986	$ 4,601	$ 1,612	$ 2,899	$ 5,763
Balance to Date	$ 294,735	$ 296,423	$ 298,360	$ 300,076	$ 301,839	$ 304,729	$ 306,301	$ 309,288	$ 313,889	$ 315,501	$ 318,399	$ 324,162
Total BLRA												
Direct Expenditures	$ 81,660	$ 50,257	$ 52,878	$ 16,870	$ 88,465	$ 84,753	$ 112,099	$ 72,999	$ 23,099	$ 22,395	$ 2,813	$ 5,706
AFUDC	$ 2,642	$ 3,215	$ 3,389	$ 3,753	$ 4,263	$ 4,680	$ 1,430	$ 4,759	$ (358)	$ (6,532)	$ 86	$ 57
CWIP for Period	$ 84,302	$ 53,472	$ 56,266	$ 20,623	$ 92,729	$ 89,432	$ 113,529	$ 77,759	$ 22,741	$ 15,863	$ 2,899	$ 5,763
Balance to Date	$4,503,270	$4,556,742	$4,613,008	$4,633,631	$4,726,360	$4,815,792	$4,929,321	$5,007,080	$5,029,821	$5,045,684	$5,048,583	$5,054,346

	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18
WO 17 - NND only*						
Direct Expenditures	$ (85,561)	$ -	$ -	$ (9,990)	$ 3	$ (3)
AFUDC	$ 898	$ -	$ -	$ -	$ -	$ -
CWIP for Period	$ (84,663)	$ -	$ -	$ (9,990)	$ 3	$ (3)
Balance to Date	$4,645,520	$4,645,520	$4,645,520	$4,635,531	$4,635,534	$4,635,531
Transmission WO's						
Direct Expenditures	$ (2,669)	$ 4,222	$ 2,970	$ (2,208)	$ 3,904	$ 1,026
AFUDC	$ 172	$ 302	$ 336	$ 339	$ 343	$ 275
CWIP for Period	$ (2,498)	$ 4,524	$ 3,307	$ (1,869)	$ 4,247	$ 1,301
Balance to Date	$ 321,665	$ 326,189	$ 329,496	$ 327,626	$ 331,873	$ 333,175
Total BLRA						
Direct Expenditures	$ (88,230)	$ 4,222	$ 2,970	$ (12,198)	$ 3,907	$ 1,023
AFUDC	$ 1,069	$ 302	$ 336	$ 339	$ 343	$ 275
CWIP for Period	$ (87,161)	$ 4,524	$ 3,307	$ (11,859)	$ 4,250	$ 1,298
Balance to Date	$4,967,185	$4,971,709	$4,975,016	$4,963,157	$4,967,407	$4,968,705

**Does not reflect impairment charges related to VCS 2 and VCS 3 CWIP.*

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-11:

Refer to the response to ORS 6-19.

a. Provide a schedule with the monthly construction history of each project identified in response to ORS 6-19 separated into non-transmission and transmission directs and AFUDC and further into allocations of these costs to Unit 1, Unit 2, and Unit 3, including the subsequent transfers from Units 2 and 3 to Unit 1. In addition, provide the amount by month incurred of each project initially allocated to Units 2 and 3 and is included in the NND project CWIP reflected in present revised rates that has since been transferred to Unit 1.

b. Provide a copy of all studies that address the need for and economics of the Offsite Water System for Unit 1 that demonstrate it would have been constructed in the absence of Units 2 and 3.

c. Indicate whether the NLC Annex would have been constructed in the absence of Units 2 and 3. Provide all support relied on for your response, including, but not limited to, a copy of all studies that address the need for and economics of the NLC Annex.

RESPONSE 7-11:

a. Please refer to attached schedule 7-11A labeled Response 7-11 on the enclosed CD.

b. Please refer to the following Offsite Water System (OWS) attachments labeled 7-11 on the enclosed CD:

   i. 7-11B OWS Options – provides certain cost/benefit analysis for abandoning the OWS and overhauling the existing Unit 1 plant versus utilizing it as a Unit 1 asset.
   ii. 7-11B OWS Operation Requirements – describes staffing requirements, staffing analysis (internal versus external), maintenance requirements, and turnover requirements.
   iii. 7-11B Unit 1 Clarifier Refurb – describes work scope to refurbish the existing Unit 1 filtered/potable water production facility to provide reliable service for another 35 years.
   iv. 7-11B OWS Completion Work Order Cost Tracking – provides a cost estimate for completion work for the OWS.

c. The NLC Annex would not have been constructed in its current location and configuration if not for the Units 2 & 3 project. After abandonment, Unit 1 needed to determine the future use of NLC Annex, the Units 2 & 3 Service Building, and the NND Building. It was decided to only retain the NLC Annex. This space allows operational, maintenance and contractor in-processing training to be centralized in the NLC "learning campus". It also levelized staff and contractor resources by allowing training to occur more often and during the required times, rather than or stopping or delaying any plant work activities due to training classroom availability. It also allowed for future retirement of the current Craft Training Center (CTC), which is utilized for access control, badging, and outage training, lowering future maintenance costs. Additionally, it also allows existing Unit 1 laboratory and staff facilities currently in the under-utilized NND Building to be relocated to the NLC Annex, thus allowing the NND Building to be retired, lowering future maintenance costs.

Responsible person: (a.) Kevin Kochems; (b.) and (c.) Kyle Young

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-12:

Provide a schedule showing each income item and deduction related to the NND project for each tax year since construction commenced. Separately show the effects of taxable losses in any year that were carried back to and utilized in prior years or carried forward to and utilized in future years by tax year, as well as the loss carryforward balance at the end of each tax year. Provide all data, assumptions, and calculations, including electronic spreadsheets in live format with all formulas intact.

RESPONSE 7-12:
Attached is a schedule of each income item and deduction by year related to NND. The computations have previously been provided in response 1-176, 4-64, and 6-27.

Attached is also a copy of Forms 1139 from 2016 and 2017. These show the amounts that were carried back to prior years. Net operating losses are carried back two years and credits are carried back one year. Taxable income and loss is calculated on a consolidated basis and includes all of SCANA Corporation and Subsidiaries.

Based on the recently filed original 2017 tax return (to be superseded later this year) there is $2,018,606,000 of taxable loss to be carried forward to 2018 and $73,115,581 of tax credits to be carried forward to 2018.

RESPONSIBLE PERSON:
Virginia Smith

ORS Request 7-12

Provide a schedule showing each income item and deduction related to the NND project 1
were carried back to and utilized in prior years or carried forward to and utilized in futu
assumptions, and calculations, including

	2007	2008	2009
BLRA Revenues			9,086,000
CPI	439,915	2,192,601	13,616,365
CPI - December Adjustment			
CPI - Transmission			
Book Debt AFC	(508,771)	(1,720,014)	(3,639,450)
Book Debt AFC - December Adjustment			
Book Debt AFC - Transmission			(9,026)
Toshiba Settlement			
174 Deductions		(10,580,786)	(37,363,743)
174 Deduction - December Adjustment			
Other nuclear deductions (internal labor costs)	(1,231,812)	(427,218)	
165 tax abandonment			
Net income / (loss)	(1,300,668)	(10,535,417)	(18,309,854)

See response to 1-176
See response to 4-64 Blue tab
See response to 4-64 Green Tab
See response to 4-64 Orange Tab
See response to 6-27
True-ups identified subsequent to earlier responses

for each tax year since construction commenced. Separately show the effects of tạ
ure years by tax year, as well as the loss carryforward balance at the end of each tạ
ʒ electronic spreadsheets in live format with all formulas intact.

2010	2011	2012	2013	2014	2015
39,143,000	88,044,000	134,896,000	188,732,000	267,087,000	335,015,000
36,269,411	59,766,352	85,762,878	109,084,771	122,198,736	163,120,479
69,468	253,081	952,970	3,987,782	8,216,977	10,458,303
(5,791,889)	(4,803,805)	(5,594,954)	(7,590,321)	(6,605,046)	(5,948,588)
(17,029)	(52,640)	(529,955)	(1,337,448)	(1,439,407)	(1,112,899)
(48,161,887)	(46,938,808)	(46,612,124)	(40,579,012)	(41,246,238)	(350,861,151)
21,511,074	96,268,180	168,874,815	252,297,772	348,212,022	150,671,144

axable losses in any year that
ax year. Provide all data,

2016	2017	Total
399,883,000	446,632,000	1,908,518,000
174,898,676	189,334,200	956,684,384
	(204,094)	(204,094)
19,567,314	12,466,316	55,972,211
(10,288,966)	(8,864,427)	(61,356,232)
	21,430	21,430
(1,314,091)	(688,408)	(6,500,903)
	1,095,230,291	1,095,230,291
(716,339,347)	(347,205,034)	(1,685,888,130)
	(5,627,606)	(5,627,606)
		(1,659,030)
	(3,667,213,896)	(3,667,213,896)
(133,593,414)	(2,286,119,228)	(1,412,023,575)

Form **1139** (Rev. November 2014) Department of the Treasury Internal Revenue Service

Corporation Application for Tentative Refund

▶ Information about Form 1139 and its separate instructions is at *www.irs.gov/form1139.*

▶ Do not file with the corporation's income tax return - file separately.

▶ Keep a copy of this application for your records.

OMB No. 1545-0123

Name: SCANA CORPORATION	Employer identification number: 57-0784499
Number, street, and room or suite no. If a P.O. box, see instructions.: 220 OPERATION WAY	Date of incorporation: 10/01/1984
City or town, state, and ZIP code: CAYCE, SC 29033-3701	Daytime phone number: (803) 217-9000

1 Reason(s) for filing. See instructions - attach computation

a Net operating loss (NOL) ▶ 57,112,028.

b Net capital loss ▶

c Unused general business credit Stmt. 71 ▶ 36,403,280.

d Other ▶

2 Return for year of loss, unused credit, or overpayment under section 1341(b)(1) ▶ a Tax year ended 12/31/2016 b Date tax return filed 09/28/2017 c Service center where filed

3 If this application is for an unused credit created by another carryback, enter ending date for the tax year of the first carryback ▶

4 Did a loss result in the release of a foreign tax credit, or is the corporation carrying back a general business credit that was released because of the release of a foreign tax credit (see instructions)? If "Yes," the corporation must file an amended return to carry back the released credits . . . ☐ Yes ☒ No

5a Was a consolidated return filed for any carryback year or did the corporation join a consolidated group (see instructions)? ☒ Yes ☐ No

b If "Yes," enter the tax year ending date and the name of the common parent and its EIN, if different from above (see instructions) ▶

6a If Form 1138 has been filed, was an extension of time granted for filing the return for the tax year of the NOL? ☐ Yes ☐ No

b If "Yes," enter the date to which extension was granted ▶ c Enter the date Form 1138 was filed. ▶

d Unpaid tax for which Form 1138 is in effect ▶ $

7 If the corporation changed its accounting period, enter the date permission to change was granted ▶

8 If this is an application for a dissolved corporation, enter date of dissolution ▶

9 Has the corporation filed a petition in Tax Court for the year or years to which the carryback is to be applied? ☐ Yes ☒ No

10 If any part of the decrease in tax due to a loss or credit resulting from a reportable transaction required to be disclosed? If Yes, attach Form 8886 ☐ Yes ☒ No

Computation of Decrease in Tax. See instructions. Note: If only filing for an unused general business credit (line 1c), skip lines 11 through 15.	2nd preceding tax year ended ▶ 12/31/2014 (a) Before carryback	(b) After carryback	1st preceding tax year ended ▶ 12/31/2015 (c) Before carryback	(d) After carryback	preceding tax year ended ▶ (e) Before carryback	(f) After carryback
11 Taxable income from tax return	327491408.	332631490.	736424416.	736424416.		
12 Capital loss carryback (see instructions)						
13 Subtract line 12 from line 11		332631490.		736424416.		
14 NOL deduction (see instructions)		57112028.				
15 Taxable income. Subtract line 14 from line 13		275519462.		736424416.		
16 Income tax	114621993.	96431812.	257748546.	257748546.		
17 Alternative minimum tax						
18 Add lines 16 and 17	114621993.	96431812.	257748546.	257748546.		
19 General business credit (see instructions)	11207491.	11207491.	23454248.	59857528.		
20 Other credits (see instructions)			1,691.	1,691.		
21 Total credits. Add lines 19 and 20	11207491.	11207491.	23455939.	59859219.		
22 Subtract line 21 from line 18	103414502.	85224321.	234292607.	197889327.		
23 Personal holding company tax (Sch. PH (Form 1120))						
24 Other taxes (see instructions)						
25 Total tax liability. Add lines 22 through 24	103414502.	85224321.	234292607.	197889327.		
26 Enter amount from "After carryback" column on line 25 for each year	85224321.		197889327.			
27 Decrease in tax. Subtract line 26 from line 25	18190181.		36403280.			
28 Overpayment of tax due to a claim of right adjustment under section 1341(b)(1) (attach computation)						

Sign Here

Under penalties of perjury, I declare that I have examined this application and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct, and complete.

▶ Signature of officer JAMES E SWAN IV ▶ Date 10/18/2017 ▶ Title CONTROLLER

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
Firm's name ▶			Firm's EIN ▶	
Firm's address ▶			Phone no.	

Form 1139, General Business Credit detail

Year	Amount	Year	Amount	Year	Amount
2001		2002		2003	
2004		2005		2006	
2007		2008		2009	
2010		2011		2012	
2013		2014		2015	

Total prior year General Business Credits	
Current year General Business Credit	36,403,280.
Total General Business Credits available	36,403,280.

Form **1139** (Rev. November 2014) Department of the Treasury Internal Revenue Service

Corporation Application for Tentative Refund

▶ Information about Form 1139 and its separate instructions is at *www.irs.gov/form1139.*
▶ Do not file with the corporation's income tax return - file separately.
▶ Keep a copy of this application for your records.

OMB No. 1545-0123

Name: SCANA CORPORATION
Employer identification number: 57-0784499
Number, street, and room or suite no. If a P.O. box, see instructions.: 220 OPERATION WAY
Date of incorporation: 10/01/1984
City or town, state, and ZIP code: CAYCE, SC 29033-3701
Daytime phone number: (803) 217-9000

1 Reason(s) for filing. See instructions - attach computation
a Net operating loss (NOL) Stmt. 1. ▶ 2,779,527,279.
b Net capital loss ▶
c Unused general business credit Stmt. 2. . . ▶ 49,525,103.
d Other ▶

2 Return for year of loss, unused credit, or overpayment under section 1341(b)(1) ▶ a Tax year ended 12/31/2017 b Date tax return filed 03/29/2018 c Service center where filed Ogden, UT

3 If this application is for an unused credit created by another carryback, enter ending date for the tax year of the first carryback ▶ 12/31/2015

4 Did a loss result in the release of a foreign tax credit, or is the corporation carrying back a general business credit that was released because of the release of a foreign tax credit (see instructions)? If "Yes," the corporation must file an amended return to carry back the released credits ☐ Yes ☒ No

5a Was a consolidated return filed for any carryback year or did the corporation join a consolidated group (see instructions)? ☒ Yes ☐ No

b If "Yes," enter the tax year ending date and the name of the common parent and its EIN, if different from above (see instructions) ▶

6a If Form 1138 has been filed, was an extension of time granted for filing the return for the tax year of the NOL? ☐ Yes ☐ No

b If "Yes," enter the date to which extension was granted ▶ c Enter the date Form 1138 was filed. ▶

d Unpaid tax for which Form 1138 is in effect ▶ $

7 If the corporation changed its accounting period, enter the date permission to change was granted ▶

8 If this is an application for a dissolved corporation, enter date of dissolution ▶

9 Has the corporation filed a petition in Tax Court for the year or years to which the carryback is to be applied? ☐ Yes ☒ No

10 If any part of the decrease in tax due to a loss or credit resulting from a reportable transaction required to be disclosed? If Yes, attach Form 8886 ☒ Yes ☐ No

Computation of Decrease in Tax See instructions.	3rd preceding tax year ended ▶ 12/31/2014		2nd preceding tax year ended ▶ 12/31/2015		preceding tax year ended ▶	
Note: *If only filing for an unused general business credit (line 1c), skip lines 11 through 15.*	(a) Before carryback	(b) After carryback	(c) Before carryback	(d) After carryback	(e) Before carryback	(f) After carryback
11 Taxable income from tax return	275519462.	275519462.	736424416.	760921238.		
12 Capital loss carryback (see instructions)						
13 Subtract line 12 from line 11		275519462.		760921238.		
14 NOL deduction (see instructions)				760921238.		
15 Taxable income. Subtract line 14 from line 13		275519462.				
16 Income tax	96431812.	96431812.	257748546.			
17 Alternative minimum tax				15270218.		
18 Add lines 16 and 17	96431812.	96431812.	257748546.	15270218.		
19 General business credit (see instructions)	11207491.	19391521.	59857528.	15270218.		
20 Other credits (see instructions)		1,691.	1,691.			
21 Total credits. Add lines 19 and 20	11207491.	19393212.	59859219.	15270218.		
22 Subtract line 21 from line 18	85224321.	77038600.	197889327.			
23 Personal holding company tax (Sch PH (Form 1120))						
24 Other taxes (see instructions)						
25 Total tax liability. Add lines 22 through 24	85224321.	77038600.	197889327.			
26 Enter amount from "After carryback" column on line 25 for each year	77038600.					
27 Decrease in tax. Subtract line 26 from line 25	8,185,721.		197889327.			
28 Overpayment of tax due to a claim of right adjustment under section 1341(b)(1) (attach computation)						

Sign Here

Under penalties of perjury, I declare that I have examined this application and accompanying schedules and statements, and to the best of my knowledge and belief, they are true, correct, and complete.

▶ Signature of officer JAMES E SWAN IV ▶ Date 6/6/18 ▶ CONTROLLER Title

Paid Preparer Use Only

Print/Type preparer's name	Preparer's signature	Date	Check ☐ if self-employed	PTIN
Firm's name ▶			Firm's EIN ▶	
Firm's address ▶			Phone no.	

For Paperwork Reduction Act Notice, see separate instructions. Form **1139** (Rev. 11-2014)

JSA
7C3500 1.000

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Form 1139, Net Operating Loss detail

Total current year NOL	2,779,527,279.

Prior Year	Prior Year Income	Carryback Absorbed
2012		
2013		
2014		
2015		760,921,238.
2016		

Total prior year taxable income absorbed	760,921,238.
Current year NOL carried over	2,018,606,041.

SCANA CORPORATION
57-0784499
FORM 1139
TAXABLE YEAR 12/31/17
CARRYFORWARD SCHEDULE
STATEMENT 2

NET OPERATING LOSS

GENERATED IN 2017	-2,779,527,279
USED - 2015 ON FORM 1139	760,921,238
CARRYFORWARD TO 2018	-2,018,606,041

CREDITS	Prior Year Generated	Generated	Used	Carryforward
RESEARCH CREDIT - 2016 generated	28,145,407		0	28,145,407
RENEWABLE ELECTRICITY PRODUCTION CREDIT - 2016	8,254,946		0	8,254,946
ALTERNATIVE FUEL VEHICLE REFUELING PROP-2016	2,927		0	2,927
SUB TOTAL 2016 CREDITS CARRYFORWARD				36,403,280
RESEARCH CREDIT - 2017 generated - SCEG		13,121,823	0	13,121,823
TOTAL PER 1139 GENERAL BUSINESS CREDITS				49,525,103
RENEWABLE ELECTRICITY PRODUCTION CREDIT - 2017		8,320,260	0	8,320,260
ALTERNATIVE MINIMUM TAX CREDIT - 2015 - 1139	15,270,218		0	15,270,218
	51,673,498	21,442,083	0	73,115,581

CONTRIBUTIONS	Prior Year Generated	Generated	Used	Carryforward
CONTRIBUTION CARRYFORWARD - 2016	3,585,739	0	0	3,585,739
CONTRIBUTION CARRYFORWARD - 2017	0	3,316,540	0	3,316,540
	3,585,739	3,316,540	0	6,902,279

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-13:

Provide a schedule that allocates the NOL asset ADIT at December 31, 2017 between NND project costs and non-NND project costs using a "but for" approach where the taxable income for each tax year since NND construction expenditures commenced is adjusted to remove the income and deductions related to the NND project provided in response to the immediately preceding question. Separately show the effects on the NOL asset ADIT of taxable losses in any year that were carried back to and utilized in prior years or carried forward to and utilized in future years by tax year, as well as the loss carryforward balance at the end of each tax year. Provide all data, assumptions, and calculations, including electronic spreadsheets in live format with all formulas intact.

RESPONSE 7-13:

The Company has considered the NOL ADIT asset as being fully allocable to NND project costs. The Company would not be in an NOL situation but for costs associated with the NND project.

RESPONSIBLE PERSON:

Virginia Smith

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-14:

Indicate whether the ADIT, other than the NOL asset ADIT, that will be used in the calculation of rate base for the CCR revenue requirements under the Merger CBP will reflect the reductions in ADIT related to the NND cost impairment loss write-offs already taken by SCE&G. Explain the response.

RESPONSE 7-14:

The ADIT liability will equal the difference between the book basis of the NND asset and the tax basis of the NND asset multiplied by the tax rate. The book basis of the NND asset will reflect the impairments taken by SCE&G and additional impairments expected to be taken by SCE&G at the closing of the merger with Dominion Energy under the CBP, such that the book basis, after impairments will equal approximately $3.33 billion.

For illustration purposes, assume the tax basis of NND is $0 and a pre-tax reform statutory income tax rate of 38.25%. The ADIT liability would be $1.27 billion.

RESPONSIBLE PERSON: William Kurz

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-15:

Indicate whether the ADIT, other than the NOL asset ADIT, that will be used in the calculation of rate base for the CCR revenue requirements under the Merger CBP will reflect the reductions in ADIT related to additional impairment loss or other write-offs proposed by the Applicants or that are related to disallowances of NND costs that may be imposed by the Commission. Explain your response.

RESPONSE 7-15:

The Customer Benefits Plan's approval, with no material changes to its terms, conditions or undertakings, and no significant change to its economic value, is an essential and requisite condition of the Merger. Without Plan approval, the Merger will not occur.

Additional impairments, write-offs proposed by the Applicants, or disallowances of NND that may be imposed by the Commission will reduce the book basis of the capital cost included in the CCR. A reduction in the book basis of the capital cost will automatically reverse a portion of the ADIT liability.

As stated in the Joint Petition, Dominion Energy's proposal is the CCR includes the capital costs of $3.33 billion, and an ADIT liability offset by the NOL asset ADIT. If the CCR capital cost of $3.33 billion is further reduced by a disallowance imposed by the Commission, the ADIT liability in the CCR must be based on the reduced book cost.

RESPONSIBLE PERSON: William Kurz

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-16:

Indicate whether the NOL asset ADIT that will be used in the calculation of rate base for the CCR revenue requirements under the Merger CBP will be reduced to reflect the reductions in ADIT related to the NND cost impairment loss write-offs already taken or that will be taken by SCE&G. If so, explain how the Company will calculate the reductions in the NOL asset ADIT. If not, explain why not.

RESPONSE 7-16:

The NOL asset ADIT represents the anticipated future reductions in income taxes payable attributable to SCE&G's net operating loss carryovers. Because this calculation is based on SCE&G's losses as computed for tax purposes, it is unaffected by any NND cost impairment loss write-offs already taken or that will be taken for GAAP purposes by SCE&G related to NND.

Internal Revenue Code Section 382 will impose an annual dollar limitation on the amount of SCE&G's net operating losses that can be used to reduce its income tax liability following the Merger. As SCE&G, as a part of Dominion Energy, is able to use its net operating losses (as computed for tax purposes) to reduce its income tax liability, the balance of the NOL asset ADIT used in the calculation of the CCR revenue requirement will be reduced.

RESPONSIBLE PERSON: William Kurz

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-17:

Indicate whether the NOL asset ADIT that will be used in the calculation of rate base for the CCR revenue requirements under the Merger CBP will be reduced to remove the portion caused by or due to the abandonment loss deductions that have or will be recognized as impairment losses for book accounting purposes. If so, describe how SCE&G will calculate the amount that should be removed from the NOL asset ADIT. If not, explain why not.

RESPONSE 7-17:

The NOL asset ADIT is not impacted by impairment losses recognized for book purposes. As explained in Response 7-16, the NOL asset ADIT represents the anticipated future reductions in income taxes payable primarily attributable to the NND project.

RESPONSIBLE PERSON: William Kurz

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-18:

Provide a calculation of the actual annualized discount rate due to the monetization of the Toshiba parental guarantee payments compared to the schedule of the amounts and timing of the Toshiba parental guarantee payments pursuant to the Toshiba settlement agreement. Provide the calculation with and without the related advisory fees and expenses incurred to negotiate the Toshiba settlement agreement and with and without the fees related to the monetization.

RESPONSE 7-18:

On July 27, 2017, South Carolina Electric & Gas Company ("SCE&G") and the South Carolina Public Service Authority ("Santee Cooper" and together with SCE&G, the "Owners"), entered into a settlement agreement with Toshiba Corporation ("Toshiba") with respect to its parent guarantee obligations under the EPC Agreement between Westinghouse, Toshiba's wholly owned subsidiary, and the Owners (the "Settlement Agreement"). The Settlement Agreement required that, among other things, Toshiba pay the Owners $2.168 billion in monthly installments between October 2017 and September 2022 (the "Claim").

Toshiba faced heightened financial pressures at the time due to losses associated with Westinghouse, which resulted in negative shareholder's equity on Toshiba's balance sheet. Toshiba had to adhere to a timeline to find a solution to eliminate its equity deficit or face a delisting from the Tokyo Stock Exchange. Uncertainty around Toshiba's financial health continued even as it attempted to address its contingent liability exposure from Westinghouse. There was continuing uncertainty as to whether Toshiba would be able to remedy its balance sheet and continue as a going concern which created risk on the scheduled monthly installment payments under the Settlement Agreement for the Owners. Under the Settlement Agreement, the Owners were subject to the same credit risk as unsecured creditors of Toshiba. The Owners determined that managing Toshiba credit risk is not a core competency and determined that monetization of the Claim was in the best interest of its constituents.

On September 27, 2017, the Owners sold their interest in the Claim (excluding the October 2017 payment) to an affiliate of Citibank N.A. for 91.530% of the $2.018 billion notional amount of the Claim being monetized. The monetization of the Claim resulted in proceeds to the Owners of $1.847 billion. As detailed in

Table I, based on the monthly stream of payments under the Settlement Agreement, the Owners' $1.997 billion of proceeds, inclusive of the $150 million October 2017 payment, implied an annualized discount rate of approximately 3.447% as of September 27, 2017.

<u>RESPONSIBLE PERSON</u>: Christina Putnam

***Table I:** Calculation of Annualized Discount Rate From Monetization of Payments as Per Schedule 2.2 Under Toshiba Parent Guarantee Settlement Agreement*

Toshiba Parent Guarantee Settlement Claim Sale Calculation (09/27/2017)	
($ in millions)	
Notional Amount of Toshiba Settlement Claim[1]	$2,168.00
(-) October 1 Payment	(150.00)
Toshiba Claim For Sale	$2,018.00
(x) Purchase Price	91.530%
Toshiba Claim Monetization Proceeds	$1,847.08
(+) October 1 Payment	150.00
Net Toshiba Parent Guarantee Proceeds	$1,997.08
Implied Annualized Discount Rate at 09/27/2017	3.447%

			NPV Analysis at 09/27/2017	
		Cumulative	@ 3.447% Discount Rate	
Date	Monthly Payments [1]	Monthly Payments	Discount Factor	NPV
Oct-17	$150.00	$150.00	99.96%	$149.94
Nov-17	32.50	182.50	99.68%	32.39
Dec-17	32.50	215.00	99.40%	32.30
Jan-18	32.50	247.50	99.11%	32.21
Feb-18	32.50	280.00	98.83%	32.12
Mar-18	32.50	312.50	98.57%	32.04
Apr-18	23.50	336.00	98.29%	23.10
May-18	23.50	359.50	98.01%	23.03
Jun-18	23.50	383.00	97.73%	22.97
Jul-18	23.50	406.50	97.46%	22.90
Aug-18	23.50	430.00	97.18%	22.84
Sep-18	23.50	453.50	96.90%	22.77
Oct-18	23.50	477.00	96.63%	22.71
Nov-18	23.50	500.50	96.35%	22.64
Dec-18	23.50	524.00	96.09%	22.58
Jan-19	23.50	547.50	95.81%	22.52
Feb-19	23.50	571.00	95.53%	22.45
Mar-19	37.50	608.50	95.29%	35.73
Apr-19	37.50	646.00	95.01%	35.63
May-19	37.50	683.50	94.75%	35.53
Jun-19	37.50	721.00	94.48%	35.43
Jul-19	37.50	758.50	94.21%	35.33
Aug-19	37.50	796.00	93.94%	35.23
Sep-19	37.50	833.50	93.67%	35.13
Oct-19	37.50	871.00	93.41%	35.03
Nov-19	37.50	908.50	93.14%	34.93
Dec-19	37.50	946.00	92.88%	34.83
Jan-20	37.50	983.50	92.62%	34.73
Feb-20	37.50	1,021.00	92.35%	34.63
Mar-20	37.50	1,058.50	92.10%	34.54
Apr-20	37.50	1,096.00	91.84%	34.44
May-20	37.50	1,133.50	91.58%	34.34
Jun-20	37.50	1,171.00	91.32%	34.24
Jul-20	37.50	1,208.50	91.06%	34.15
Aug-20	37.50	1,246.00	90.80%	34.05
Sep-20	37.50	1,283.50	90.54%	33.95
Oct-20	37.50	1,321.00	90.29%	33.86
Nov-20	37.50	1,358.50	90.03%	33.76
Dec-20	37.50	1,396.00	89.78%	33.67
Jan-21	37.50	1,433.50	89.52%	33.57
Feb-21	37.50	1,471.00	89.26%	33.47
Mar-21	37.50	1,508.50	89.03%	33.39
Apr-21	37.50	1,546.00	88.78%	33.29
May-21	37.50	1,583.50	88.53%	33.20
Jun-21	37.50	1,621.00	88.28%	33.10
Jul-21	37.50	1,658.50	88.03%	33.01
Aug-21	37.50	1,696.00	87.78%	32.92
Sep-21	37.50	1,733.50	87.52%	32.82
Oct-21	37.50	1,771.00	87.28%	32.73
Nov-21	37.50	1,808.50	87.03%	32.64
Dec-21	37.50	1,846.00	86.79%	32.55
Jan-22	37.50	1,883.50	86.54%	32.45
Feb-22	37.50	1,921.00	86.29%	32.36
Mar-22	37.50	1,958.50	86.07%	32.27
Apr-22	37.50	1,996.00	85.82%	32.18
May-22	37.50	2,033.50	85.58%	32.09
Jun-22	37.50	2,071.00	85.33%	32.00
Jul-22	37.50	2,108.50	85.10%	31.91
Aug-22	37.50	2,146.00	84.85%	31.82
Sep-22	22.00	2,168.00	84.61%	18.61
Total	$2,168.00			$1,997.08

Notes: Numbers shown in USD millions and rounded to two decimal places - may not sum due to rounding

(1) The cash flows reflect the claim payment schedule in Schedule 2.2 to the Toshiba Parental Guarantee Settlement Agreement. SCE&G had rights to 55% of the cash flows.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-19:

Refer to page 3 of the V.C. Summer Units 2 and 3 Redress Plan attached to the response to ORS 5-17 wherein it states:

a. *Under current plans, the existing containment, turbine, and associated support buildings would not be demolished but would remain in their currently constructed state. The other structures not identified as necessary would be removed from the site, abandoned in place, or demolished.*

   i. Indicate when SCE&G plans to demolish and remove the facilities that will "remain in their currently constructed state."

   ii. Will the former construction site be restored? If so, describe the scope and timing of the planned restoration.

   iii. Provide estimates in 2018 dollars for the demolition and removal of these facilities and restoration of the site. Provide all support used to develop the estimate.

   iv. Indicate whether SCE&G will hold its customers harmless from the costs to demolish and remove the facilities that will "remain in their currently constructed state" and restore the site. If not, then explain why not.

   v. Indicate if it is the intent of SCE&G to include the cost to demolish and remove the facilities constructed for Units 2 and 3 in the cost to demolish and remove the facilities for Unit 1 in subsequent Unit 1 decommissioning studies. If so, explain why the Unit 2 and 3 costs should not be addressed in conjunction with the recovery of NND costs in this proceeding.

RESPONSE 7-19:

i. SCE&G does not plan to demolish or remove any facilities. These facilities have been abandoned and any ownership by SCE&G will be transferred to Santee Cooper.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
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DOCKET NO. 2017-370-E (7th Continuing AIR)

ii. There are no plans currently by SCE&G to restore the former construction site. SCE&G will be closing out and terminating construction stormwater permits and other permits, which it does not consider the same as restoration.

iii. Since there are no plans for demolition and restoration of the former construction site by SCE&G, there is no associated cost estimate.

iv. Since there are no plans currently by SCE&G to restore the former construction site, there is no current need for customers to incur costs.

v. The assets associated with Units 2 & 3, which were abandoned and ownership will be transferred to Santee Cooper, are not directly associated with the assets of Unit 1. Therefore, there is no need to include these items any Unit 1 studies. Any assets that were transferred to Unit 1 from Units 2 & 3 would be treated the same as all current Unit 1 assets in any future studies.

Responsible person: Kyle Young

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-20:

ORS 5-17 asked the Applicants to "provide the details (e.g., contract, letter of agreement, letter of transfer) of the proposal from SCE&G to Santee Cooper where Santee Cooper is to assume responsibility for all equipment at the NND project." The response provided a copy of the letter from SCE&G to the NRC seeking to withdraw the VCSNS Unit 2&3 COLs, which references the SCE&G offer to Santee Cooper; however, it provided no document addressed to Santee Cooper with an offer or detailing a proposal. If there is none, then so state. If there are any such documents, then provide them.

RESPONSE 7-20:

On November 30, 2018, SCE&G met with Santee Cooper to discuss how SCE&G could assist Santee Cooper with its efforts to preserve the abandoned project site. Attached to this response is copy of the document that SCE&G presented to Santee Cooper outlining two options. By letter dated December 4, 2017, a copy of which is attached to this response, Santee Cooper rejected both options.

After SCE&G filed its December 27, 2017 letter with the United States Regulatory Commission ("NRC") requesting withdrawal of the V.C. Summer Units 2 and 3 combined licenses ("COL"), Santee Cooper filed a letter dated January 8, 2018, requesting that the NRC not take action on SCE&G's COL withdrawal request for 180 days. Thereafter, SCE&G and Santee Cooper engaged in discussions (both verbal and written) which led to SCE&G presenting a "Forbearance Agreement" to Santee Cooper on January 30, 2018, a copy of which is attached. The Forbearance Agreement provided Santee Cooper, subject to certain conditions, the ability to preserve and maintain the project site. Santee Cooper, however, did not accept he Forbearance Agreement. Santee Cooper then presented SCE&G with two documents, one identified as a "Preliminary Forbearance Agreement" on February 22, 2018 and another identified as a "Transfer Option Agreement" on February 27, 2018. Both documents are attached to this response. SCE&G could not accept the Transfer Option Agreement because it was inconsistent with the abandonment.

SCE&G provided Santee Cooper a standard form Right of Entry Agreement on March 2, 2018 which would allow Santee Cooper's contractors access to the site. A copy of the March 2, 2018 right of entry form is attached to this response.

Various drafts have been exchanged since, but the overriding issue has been SCE&G's concern that as a licensee of the project, it could not agree to allow Santee Cooper to undertake the requested activities at the site without the approval of the NRC. In response to requests from both SCE&G and Santee Cooper, the NRC consented to Santee Cooper's proposed activities by letter dated June 6, 2018. The parties have now verbally agreed on a form document, a copy of which is attached hereto, to allow the activities to take place.

<u>RESPONSIBLE PERSONS</u>: Virginia Smith

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-21:

Refer to the Companies' response to ORS 4-49:

a. Provide the specific "service levels in our contact center operations (% of all answered within a specific amount of time)". Provide the percentages monthly from 2012 through the most recent month in 2018. Provide all support work papers and documentation for this response.

b. Provide the specific metrics monitored by SCE&G for its customer contacts quality program monthly from 2012 through the most recent month in 2018. Provide all work papers and documentation for this response.

c. Provide the specific metrics monitored by SCE&G for its customer accuracy program monthly from 2012 through the most recent month in 2018. Provide all work papers and documentation for this response.

d. Provide the SAIDI and SAIFI results including MEDs for 2013 through 2017. Provide a detailed explanation as to how the Company defines a MED. Provide supporting work papers and documentation for the MEDs that were excluded from the SAIDI and SAIFI values provided in the response.

RESPONSE 7-21:

Please see attached.

RESPONSIBLE PERSONS: Brent Wininger and Kevin Monaghan (7-21 a.), Lisa Hill and Slywia Wright (7-21 b.), Lisa Hill and Cindy Hux (7-21 c.), and Carol Clements (7-21 d)

Response to 7-21a

SCE&G Call Volume and Service Level Summary

6/12/2018

Data is sourced from our Avaya ACD (Automated Call Distribution - Phone Switch) reporting database replicated in our SCANA IT data warehouse.

Service level is calculated on following SCE&G ACD skills tied to main Customer Service and Outage Emergency Toll-Free numbers:
SCEG Outage, SCEG Credit, SCEG Emergency, SCEG Orders, SCEG CIS (General), SCEG Spanish, SCEG 911

Service Level Formula calculated for individual ACD skill by day, displayed as a combined weighted average, monthly based on calls answered (Agent Calls Only).

Calls abandoned while waiting in queue are excluded from this Service Level calculation.

	Calls Answ'd	Calls Answered Within 20Seconds	80/20 Service Level
SCEG			
January 2012	163,277	131,179	80.34%
February 2012	153,755	130,685	85.00%
March 2012	157,505	140,426	89.16%
April 2012	151,815	133,077	87.66%
May 2012	161,182	144,718	89.79%
June 2012	156,617	135,523	86.53%
July 2012	180,654	140,906	78.00%
August 2012	191,113	148,232	77.56%
September 2012	165,540	133,074	80.39%
October 2012	186,794	154,738	82.84%
November 2012	166,959	138,982	83.24%
December 2012	155,477	123,254	79.27%
January 2013	173,587	129,279	74.48%
February 2013	159,342	106,077	66.57%
March 2013	163,419	129,145	79.03%
April 2013	169,174	136,902	80.92%
May 2013	170,152	134,896	79.28%
June 2013	170,545	140,185	82.20%
July 2013	187,029	150,808	80.63%
August 2013	187,130	154,876	82.76%
September 2013	174,388	143,924	82.53%
October 2013	181,548	155,167	85.47%
November 2013	162,785	137,817	84.66%
December 2013	158,508	143,677	90.64%
January 2014	177,745	143,869	80.94%
February 2014	231,891	186,817	80.56%
March 2014	176,435	151,344	85.78%
April 2014	170,779	152,784	89.46%
May 2014	172,407	147,269	85.42%
June 2014	169,848	149,704	88.14%
July 2014	214,497	176,869	82.46%
August 2014	184,179	158,584	86.10%
September 2014	180,214	144,115	79.97%
October 2014	185,738	147,112	79.20%
November 2014	160,937	117,152	72.79%
December 2014	166,192	146,208	87.98%
January 2015	172,158	145,678	84.62%
February 2015	165,426	138,344	83.63%
March 2015	174,099	137,830	79.17%

Response to 7-21a

April 2015	175,516	128,802	73.38%
May 2015	180,093	141,221	78.42%
June 2015	179,365	159,261	88.80%
July 2015	192,119	150,814	78.50%
August 2015	197,418	153,742	77.88%

Response to 7-21a

September 2015	188,981	159,736	84.52%
October 2015	195,667	148,309	75.80%
November 2015	170,693	130,553	76.48%
December 2015	167,748	134,949	80.45%
January 2016	166,130	141,813	85.36%
February 2016	175,521	141,422	80.57%
March 2016	173,894	146,511	84.25%
April 2016	171,205	112,360	65.63%
May 2016	172,014	136,862	79.56%
June 2016	181,394	139,715	77.02%
July 2016	174,802	130,349	74.57%
August 2016	196,007	154,373	78.76%
September 2016	193,800	152,608	78.75%
October 2016	254,320	184,225	72.44%
November 2016	174,075	102,249	58.74%
December 2016	160,879	108,950	67.72%
January 2017	162,472	139,214	85.68%
February 2017	154,209	118,033	76.54%
March 2017	165,907	132,338	79.77%
April 2017	146,456	117,934	80.53%
May 2017	152,602	119,087	78.04%
June 2017	153,284	128,081	83.56%
July 2017	158,311	115,244	72.80%
August 2017	169,276	137,105	80.99%
September 2017	176,990	124,968	70.61%
October 2017	167,528	104,505	62.38%
November 2017	151,932	94,178	61.99%
December 2017	139,330	83,193	59.71%
January 2018	157,864	67,153	42.54%
February 2018	148,136	59,945	40.47%
March 2018	158,173	87,205	55.13%
April 2018	149,876	117,513	78.41%
May 2018	149,518	125,590	84.00%

Response to 7-21b.

Call Assessment Form

(Revised 12/2/16)

(Comment boxes available for each section and each line item.)

1.0	**OPENING** Goal: Begin every interaction in a manner that sets an inviting and professional tone, conveying a cheerful willingness to assist the caller.	**14**	**Yes**	**No**
Q1.1	Our customer was greeted promptly.	1		
Q1.2	Our customer was greeted with our standard greeting in a friendly, inviting manner	1		
Q1.3	Our customer's initial statement/reason for calling was appropriately acknowledged with a phrase that conveys a willingness to help.	2		
Q1.4	Our customer's identity was properly obtained/verified.	5		
Q1.4a	All Flagged communications were appropriately viewed/added/updated.			-5
Q1.5	Our customer's information was created/updated correctly when appropriate.	5		
2.0	**PROFESSIONAL COMMUNICATION** Goal: Create an environment that is professional and warm. The created environment should ensure the interaction is polite and one that creates a positive customer experience. Creating the desired environment is the responsibility of the representative.	**47**	**Yes**	**No**
Q2.1	We interacted with our customer in a pleasant manner and effective tone.	15		
Q2.2	Our customer was allowed to speak without interruption.	2		
Q2.3	Our customer's request(s) were fully understood using effective active listening skills.	2		
Q2.4	Our customer was not asked/required to repeat themselves unnecessarily.	2		
Q2.5	Our customer was provided an explanation for moments of silence.	2		
Q2.6	We demonstrated care and concern for our customer by making effective empathetic/apologetic statements when appropriate.	5		
Q2.7	We accommodated our customer by adapting and making adjustments as necessary.	2		
Q2.8	We spoke in terms easily understood by the customer by avoiding jargon/slang.	2		
Q2.9	Our customer interaction included positive, confident word choices.	2		
Q2.10	We communicated clearly and understandably.	2		
Q2.11	We took responsibility for our customer's concern in a manner that maintains company credibility.	2		
Q2.12	We attempted to assist the customer prior to transferring.	5		
Q2.13	We showed respect for our customer's time by appropriately managing hold and transfer procedures	2		
Q2.14	We effectively managed the call throughout the interaction	2		
3.0	**ADDRESSING OUR CUSTOMER'S NEEDS** Goal: Handle each customer interaction in a manner which demonstrates 3 priorities: (1) an understanding of the customer's need, (2) an understanding of our systems, products and processes, and (3) issue resolution.	**39**	**Yes**	**No**
Q3.1	Our customer was provided accurate information.	12		
Q3.2	Our customer was provided complete information.	3		
Q3.3	Transactions/Orders needed to handle this customer's request were accurately entered, updated and/or deleted when appropriate.	12		
Q3.4	All Transaction/Order details were entered/requested accurately as appropriate.	3		
Q3.5	The interaction included confirmation of next steps, issue resolution and/or completed transaction(s).	3		
Q3.6	The decision(s) made for this customer effectively balanced the needs of our customer and our business. *Reasonable/Good business decision.*	2		
Q3.7	**The communication details were accurately entered.**	2		
Q3.8	**The communication comments were accurately noted.**	2		
BONUS	For our customer's convenience/benefit, available options were offered when appropriate.	NA	3	

Response to 7-21b.

NEW FORM DRAFT

12/2/2016

(Comment boxes available for each section and each line item.)

1.0	OPENING	14	Yes	No
Q1.1	Our customer was greeted promptly.	1		
Q1.2	Our customer was greeted with our standard greeting in a friendly, inviting manner	1		
Q1.3	Our customer's initial statement/reason for calling was appropriately acknowledged with a phrase that conveys a willingness to help.	2		
Q1.4	Our customer's identity was properly obtained/verified.	5		
Q1.4a	All Flagged communications were appropriately viewed/added/updated.			-5
Q1.5	Our customer's information was created/updated correctly when appropriate.	5		
2.0	**PROFESSIONAL COMMUNICATION**	**47**	**Yes**	**No**
Q2.1	We interacted with our customer in a pleasant manner and effective tone.	15		
Q2.2	Our customer was allowed to speak without interruption.	2		
Q2.3	Our customer's request(s) were fully understood using effective active listening skills.	2		
Q2.4	Our customer was not asked/required to repeat themselves unnecessarily.	2		
Q2.5	Our customer was provided an explanation for moments of silence.	2		
Q2.6	We demonstrated care and concern for our customer by making effective empathetic/apologetic statements when appropriate.	5		
Q2.7	We accommodated our customer by adapting and making adjustments as necessary.	2		
Q2.8	We spoke in terms easily understood by the customer by avoiding jargon/slang.	2		
Q2.9	Our customer interaction included positive, confident word choices.	2		
Q2.10	We communicated clearly and understandably.	2		
Q2.11	We took responsibility for our customer's concern in a manner that maintains company credibility.	2		
Q2.12	We attempted to assist the customer prior to transferring.	5		
Q2.13	We showed respect for our customer's time by appropriately managing hold and transfer procedures	2		
Q2.14	We effectively managed the call throughout the interaction	2		
3.0	**ADDRESSING OUR CUSTOMER'S NEEDS**	**39**	**Yes**	**No**
Q3.1	Our customer was provided accurate information.	12		
Q3.2	Our customer was provided complete information.	3		
Q3.3	**Transactions/Orders** needed to handle this customer's request were accurately entered, updated and/or deleted when appropriate.	12		
Q3.4	All Transaction/Order **details** were entered/requested accurately as appropriate.	3		
Q3.5	The interaction included confirmation of next steps, issue resolution and/or completed transaction(s).	3		
Q3.6	The decision(s) made for this customer effectively balanced the needs of our customer and our business. ***Reasonable/Good business decision.***	2		
Q3.7	**The communication details were accurately entered.**	2		
Q3.8	**The communication comments were accurately noted.**	2		
BONUS	For our customer's convenience/benefit, available options were offered when appropriate.	NA	3	

Response to 7-21b.

Call Assessment Form

(Revised 04/13/18)

(Comment boxes available for each section and each line item.)

1.0	**OPENING** **Goal: Begin every interaction in a manner that sets an inviting and professional tone, conveying a cheerful willingness to assist the caller.**	**14**	**Yes**	**No**
Q1.1	Our customer was greeted promptly.	1		
Q1.2	Our customer was greeted with our standard greeting in a friendly, inviting manner	1		
Q1.3	Our customer's initial statement/reason for calling was appropriately acknowledged with a phrase that conveys a willingness to help.	2		
Q1.4	Our customer's identity was properly obtained/verified.	5		
Q1.4a	Flagged communications were appropriately viewed/added/updated.			-5
Q1.5	Our customer's information was created/updated correctly when appropriate.	5		
2.0	**PROFESSIONAL COMMUNICATION** **Goal: Create an environment that is professional and warm. The created environment should ensure the interaction is polite and one that creates a positive customer experience.** ***Creating the desired environment is the responsibility of the representative.***	**47**	**Yes**	**No**
Q2.1	We interacted with our customer in a pleasant manner and effective tone.	15		
Q2.1a	We interacted with proper inflection throughout the call avoiding any partial monotone/indifference			-10
Q2.2	Our customer was allowed to speak without interruption.	2		
Q2.3	Our customer's request(s) were fully understood using effective active listening skills.	2		
Q2.4	Our customer was not asked/required to repeat themselves unnecessarily.	2		
Q2.5	Our customer was provided an explanation for moments of silence.	2		
Q2.6	We demonstrated care and concern for our customer by making effective empathetic/apologetic statements when appropriate.	5		
Q2.7	We accommodated our customer by adapting and making adjustments as necessary.	2		
Q2.8	We spoke in customer terms by avoiding jargon/slang.	2		
Q2.9	Our customer interaction included positive, confident word choices.	2		
Q2.10	We communicated clearly and understandably.	2		
Q2.11	We took responsibility for our customer's concern in a manner that maintains company credibility.	2		
Q2.12	We attempted to assist the customer prior to transferring.	5		
Q2.13	We showed respect for our customer's time by appropriately managing hold and transfer procedures	2		
Q2.14	We effectively managed the call throughout the interaction	2		
3.0	**ADDRESSING OUR CUSTOMER'S NEEDS** **Goal: Handle each customer interaction in a manner which demonstrates 3 priorities: (1) an understanding of the customer's need, (2) an understanding of our systems, products and processes, and (3) issue resolution.**	**39**	**Yes**	**No**
Q3.1	All significant **credit, billing and/or general** information related to the account and/or transaction details were accurately discussed, entered, updated and/or deleted.	12		
Q3.2	Supplemental **credit, billing, and/or general** information related to the account and/or transaction details were accurately discussed, entered, updated and/or deleted when appropriate.	3		
Q3.3	All significant **Service Request transaction details** were accurately discussed, entered, updated and/or deleted.	12		
Q3.4	Supplemental **Service Request transaction details** were accurately discussed, entered, updated and/or deleted when appropriate	3		
Q3.5	The interaction included confirmation of next steps, issue resolution and/or completed transaction(s).	3		
Q3.6	The decision(s) made for this customer effectively balanced the needs of our customer and our business. *Reasonable/Good business decision.*	2		
Q3.7	**The communication** details **were accurately entered.**	2		
Q3.8	**The communication** comments **were accurately noted.**	2		
BONUS	For our customer's convenience/benefit, available options were offered when appropriate.	NA	3	

Response to 7-21b.

Email Assessment Form

(Revised 04/23/18)

(Comment boxes available for each section and each line item.)

1.0	**Email Structure** Goal: Respond to our customers in a friendly and professional manner.	**13**	**Yes**	**No**
Q1.1	Greeting- Our customer was greeted with our standard greeting	1		
Q1.2	Acknowledgement-Our customer's statement/reason for contacting us was appropriately acknowledged in a courteous and professional manner.	2		
Q1.3	Appearance-The message was uniform in appearance.	2		
Q1.4	Verification-Our customer's identity was properly obtained/verified.	5		
Q1.5	Organization -The message was wellorganized.	2		
Q1.6	Closing-The message was closed with the standard closing statement.	1		
2.0	**PROFESSIONAL COMMUNICATION** Goal: Create an environment that is professional and warm. The created environment should ensure the interaction is polite and one that creates a positive customer experience. Creating the desired environment is the responsibility of the representative. Creating the desired environment is the responsibility of the representative.	**45**	**Yes**	**No**
Q2.1	Tone - The tone of the message was friendly and professional	15		
Q2.2	Reading & Comprehension - Our customer's request(s) were fully understood and the customer was not asked/required to repeat themselves unnecessarily.	2		
Q2.3	Empathy/Apology-We demonstrated care and concern for our customer by making effective empathetic/ apologetic statements when appropriate.	4		
Q2.4	Language-We communicated in customer terms easily understood by the customer by avoiding jargon/slang.	2		
Q2.5	Word Choices-Our message included positive, confident word choices.	2		
Q2.6	Proiper Grammar-Message followed grammar rules and was free of spelling errors.	5		
Q2.7	Clear Communication- We communicated clearly and understandably.	5		
Q2.8	Company Credibilty- We took responsibility for our customer's concern in a manner that maintains company credibility.	6		
Q2.9	Assistance- We attempted to assist the customer prior to directing to another resource.	4		
3.0	**ADDRESSING OUR CUSTOMER'S NEEDS** Goal: Handle each customer interaction in a manner which demonstrates 3 priorities: (1) an understanding of the customer's need, (2) an understanding of our systems, products and processes, and (3) issue resolution.	**42**	**Yes**	**No**
Q3.1	All significant credit, billing and/or general information related to the account and/or transaction details were accurately discussed, entered, updated and/or deleted.	13		
Q3.2	Supplemental credit, billing and/or general information related to the account and/or transaction details were accurately discussed, entered, updated and/or deleted when appropriate.	3		
Q3.3	All significant Service Request transaction details were accurately discussed, entered, updated and/or deleted.	14		
Q3.4	Supplemental Service Request transaction details were accurately discussed, entered, updated and/or deleted when appropriate.	3		
Q3.5	Next Steps- The message included clear instructions for next steps.	3		
Q3.6	Business Decisions -The decision(s) made for this customer effectively balanced the needs of our customer and our business.	2		
Q3.7	Type/ Subtype- The communication details were accurately entered	2		
Q3.8	Comments - The communication comments were accurately noted.	2		
BONUS	For our customer's convenience/benefit, available options were offered when appropriate.	NA	3	

Response to 7-21b.

QUALITY FORM (SCORED)

Call Info							
1.0	**CUSTOMER CARE**	**Pts Poss**	**Yes**	**Coaching**	**No**	**Tip**	**NA**
1.1	Demonstrated professionalism & friendliness thru-out call	5					
1.2	Used an effective tone of voice throughout the call	10					
1.3	Effectively expressed sincere empathy and/or apologies	5					
1.4	Effectively managed the call throughout the interaction	5					
1.5	Remained engaged with the cust throughout the interaction	5					
1.6	Spoke positively	5					
Customer Care Comments:							
2.0	**ADDRESS CALLER'S NEED**	**Pts Poss**	**Yes**	**Coaching**	**No**	**Tip**	**NA**
2.1	Provided Accurate and complete information	10					
2.2	Accurately entered, updated and/or deleted all orders/trans	10					
2.3	Used effective questioning techniques to gain clarification	5					
2.4	Effectively summrzd main point of call and/or next steps	5					
Addressing the Customer's Needs Comments:							
3.0	**SUPPORT BUSINESS OBJECTIVES**	**Pts Poss**	**Yes**	**Coaching**	**No**	**Tip**	**NA**
3.1	Properly obtained Verified and updated customer info	5					
3.2	Accurately and completely documented the account	5					
Tracking Questions - No Scoring Impact							
3.3	Avoided an URC (Unnecessary Repeat Call) and/or was proactive regarding NIR (Next Issue Resolution)	0					
3.4	One-Contact Resolution Achieved	0					
Support Business Objectives Comments:							

Response 7-21 c.

SCE&G Quality Accuracy Program

- SCE&G's accuracy program utilizes data to analyze processes, technology and staffing resources in order to improve the customer experience and business efficiencies.
- Errors are reported through SCE&G's Customer Information System (CIS) for all business areas, including Customer Service (contact centers, business offices and billing), Operations (electric and gas), Field Services, and Sales & Marketing.
- Reviews are conducted to identify possible CIS issues, system defects, and/ or necessary training needs.
- The accuracy program has been in place since 2012, with modifications to the accuracy categories on an occasional basis.

Accuracy categories:

ACCOUNT SET UP INCORRECTLY
ADDITIONAL DOCUMENTATION NOT REQUESTED
APPLIANCES NOT ADDED SELECTED/UPDATED
APPLIANCES NOT ADDED, SELECTED/INCORRECT
APPOINTMENT/ ARRANGEMENTS HANDLED INCORRECTLY
BBP HANDLED INCORRECTLY
CHARGES NOT DOCUMENTED/INCORRECT - AFTER HRS CHARGE
CHARGES NOT DOCUMENTED/INCORRECT - HOLIDAY CHARGE
CHARGES NOT DOCUMENTED/INCORRECT - SERVICE CHARGE
CHARGES NOT REMOVED
CREDIT ACTION NOT STOPPED
CREDIT ACTION NOT STOPPED - DPP
CREDIT ACTION NOT STOPPED - MEDICAL CERTIFICATE
CROSS STREETS NOT ENTERED ON ORDER
CUSTOMER FORCED OFF IN ERROR
CUSTOMER NOT CONTACTED TIMELY
CUSTOMER WAS PROVIDED INSUFFICENT OR INCORRECT INFORMATION
DECEASED PROCESS NOT FOLLOWED
DEPOSIT NOT BILLED OR INCORRECT
DISPATCHER NOT CALLED
DISPATCHER NOT CALLED - HAZARDOUS SITUATIONS
DISPATCHER NOT NOTIFIED TO ISSUE OR UPDATE ORDER
DISPATCHER SUPPORT
DNP IN ERROR
DNP IN ERROR-DPP NOT SET UP CORRECTLY
DPP HANDLED INCORRECTLY

DRAFT NOT CANCELLED CORRECTLY
DUPLICATE ORDER PLACED
ELECTRIC OPERATIONS
ENDV CHARGES NOT HANDLED
ENDV HANDLED INCORRECTLY
FINAL BILL HANDLED INCORRECTLY
FINAL BILL/SPEC MAIL ADDRS NOT ADDED OR INCORRECT
FRO PROCESS HANDLED INCORRECTLY
FRO PROCESS HANDLED INCORRECTLY/IMPROPER ACCT REC
GAS OPERATIONS (DISPATCH NOT CALLED) - AFTER HOURS
GAS OPERATIONS(ORDER NOT PRINTED)
HIGH BILL PROCESS HANDLED INCORRECTLY
HOT OFF PROCESS NOT HANDLED CORRECTLY
IDENTITY VERIFICATION FORM PROCESS HANDLED INCORRECT
INCORRECT ADDRESS
INCORRECT ADDRESS - OUTAGE/STORM
INCORRECT CYCLE/ROUTE
INCORRECT DATE SELECTED
INCORRECT DATE SELECTED - JOBBING
INCORRECT INFORMATION ENTERED
INCORRECT NAME ENTERED
INCORRECT ORDER - COMMERCIAL EQUIPMENT
INCORRECT ORDER - SHOULD HAVE ADVISED CUSTOMER TO CALLED 811
INCORRECT ORDER ISSUED
INCORRECT ORDER TYPE
INCORRECT ORDER TYPE - NEW ACCOUNT NOT SET UP
INCORRECT ORDER TYPE - ABANDON SERVICE
INCORRECT ORDER TYPE - FURNACES
INCORRECT ORDER TYPE - HAZARDOUS SITUATIONS
INCORRECT ORDER TYPE - JOBBING
INCORRECT ORDER TYPE - LIGHTING
INCORRECT ORDER TYPE - MARKETING ORDER NOT ISSUED
INCORRECT ORDER TYPE - NEW ACCOUNT NOT SET UP
INCORRECT ORDER TYPE - OCCUPANT CHANGE
INCORRECT ORDER TYPE - ORDER CANCELED IN ERROR
INCORRECT ORDER TYPE - ORDER NOT NEEDED
INCORRECT ORDER TYPE - ORDER WAS ON HOLD FOR AROP
INCORRECT ORDER TYPE - RANGE
INCORRECT ORDER TYPE - RESTORE USED INCORRECTLY
INCORRECT ORDER TYPE - RETIRED SERVICE ERROR - SALES CALL REQUIRED
INCORRECT ORDER TYPE - SEALED GAS LOGS
INCORRECT ORDER TYPE - SEASONAL BLOCK
INCORRECT ORDER TYPE - SPLIT ORDERS
INCORRECT ORDER TYPE/WORK TYPE
INCORRECT WORK TYPE
INCORRECT WORK TYPE - HAZARDOUS SITUATIONS
INCORRECT WORK TYPE - RELEASE BOX NOT CHECKED

INSUFFICIENT INFORMATION OBTAINED FROM CUSTOMER
INSUFFICIENT OR INCORRECT INFORMATION FROM THE FIELD
INSUFFICIENT OR INCORRECT INFORMATION PROVIDED TO THE CUSTOMER
INSUFFICIENT OR NO COMMENTS ON ORDER
INSUFFICIENT/NO COMMENTS(REPAIRS, TURN DOWN, ETC)
INTERSECTION SET UP INCORRECTLY
ISSUED HIGH USE TASK FOR PSNC ACCT
ISSUED ORDER ON WRONG ACCOUNT
JOBBING ORDER NOT PRINTED
MTR & AREA ACCESSIBILITY (NON-SAFETY)
NEW ACCOUNT NOT SET UP
NO CREDIT CHECK PERFORMED - NEW CUSTOMER
NO MAILING ADDRESS FOR LIGHTING ACCOUNT
NOTES ON ORDER ARE INCORRECT
OFF NOT CHANGE TO CUST CHG/OFF ISSUED, CC PENDING
ORDER ISSUED ON WRONG ACCOUNT
ORDER NOT COMPLETED
ORDER NOT ENTERED
ORDER NOT ENTERED - HAZARDOUS SITUATION
ORDER NOT ENTERED ON MOST RECENT ACCOUNT
ORDER POSTED BUT WORK NOT COMPLETED IN FIELD
ORDER POSTED TO WRONG ACCOUNT
ORDER PRINTED/JOBBING
ORDER PRINTED/NOT PRINTED WHEN NECESSARY
ORDER STATE CHANGED/NOT CHANGED
OUTAGE REMARKS DO NOT AGREE WITH TYPE & CONDITION
PAYMENT ARRANGEMENTS MADE WHILE REP ONSITE/ IN ROUTE
POSTED WITH INCORRECT METER NUMBER
POSTED WITH INCORRECT METER STATUS OR REASON
POSTED WITH INCORRECT READING
POSTING NOT COMPLETED
PREMISE SETUP INCORRECT/DUPLICATE
RECONNECT CHARGE NOT BILLED/INCORRECT
RECONNECT CHARGE NOT DOCUMENTED/INCORRECT
RELEASE BOX CHECKED IN ERROR
REPAIRS COMPLETED NOT DOCUMENTED
RESTORE ORDER USED INCORRECTLY
RISK MATRIX NOT FOLLOWED
RISK MATRIX NOT FOLLOWED-AH INFORMATION DISCUSSED WITH SOMEONE NOT LISTED ON PROPERTY
SERVICE CARE CHARGES NOT DOCUMENTED/INCORRECT
SET/REMOVE METER WITHOUT A SERVICE ORDER
SS# NOTED ON CUSTOMERS ACCOUNT
SUPPORT REQUEST
TASK HANDLED INCORRECTLY
TRANSFER PROCESS NOT COMPLETED
WRITE OFF HANDLED INCORRECTLY

Person Responsible: Lisa Hill and Cindy Hux

ACCURACY PROGRAM OVERVIEW AND GUIDELINES

REPORTING

Quality Assurance will provide Monthly reporting and YTD reporting of all data to each responsible area by the 5th of each month for the previous month's closing. This report will include all issues received in the prior month and any pertinent data related to each issue.

Any issue of a high impact (service affecting) will be emailed to the Supervisor of the responsible party, copying the Manager. Immediate notification will be provided based on the following:

- Credit Action Not Canceled (CANS)
- Disconnect in Error
- Hazardous Issues
- Other issues as identified by accuracy as service affecting needing immediate attention

Notifications will include a screenshot of the account information, the reported issue, and guidance topic (where applicable).

DATA REVIEW

Quality Assurance will review the data monthly, as well as year to date, in order to identify possible CIS process issues or system defects.

Consideration will also be given regarding individual/group contributors in a specific category to include: New Hire teams, Specialty Groups, or individuals that may be in need of immediate attention.

Training will review the data monthly and schedule a meeting with Quality Assurance to discuss opportunities for additional training, communications, systems enhancements, and/or CIS process changes based on the following:

- Reported volume of a specific issue
- Trending
- Change in process or guideline

Managers and Supervisors should review the data monthly to identify individual performance trends and/or team performance.

- Consolidated Reporting tab provides All issues/All areas and should be used to identify specific issues by groups and/or areas of concern.
- By Employee tab provides specific Type/Sub Type and # of occurrences by employee and should be used to identify individual needs for coaching.

COACHING

Quality Assurance

- Provide support as needed by Managers, Supervisors, Leads, or Customer Service Representatives to include clarification of a specific issue, providing guidance to prevent future occurrences or presenting topics at a team meeting.
- Provide monthly topic/s for review in team meetings based on trends.

Managers and Supervisors **(Team Coaching)**

- Present the monthly topic/s provided by Accuracy to your teams and ask for discussion without identifying specific individuals.
- Encourage feedback from your teams regarding any specific process they may have that helps them eliminate these types of occurrences.
- Review the guidance topic and provide specific challenges others may be having regarding this specific topic and encourage feedback from the representatives.

Managers and Supervisors **(Individual Coaching)**

- Provide coaching to individuals with multiple occurrences of a specific type or subtype (preferably in person)
- Provide coaching to individuals with higher than average overall errors
- Provide coaching to the Type/Sub Type not account by account.
- Utilize Guidance topic to walk the employee through the process
- Consider the number of calls handled and trends. Single issues should not require coaching unless trends are occurring. Addressing one-offs with an individual may be seen as negative feedback with no meaningful purpose/result.

Response to 7-21d:

SCE&G uses the IEEE Standard 1366 Beta method to identify Major Event Days (MED) days. A PDF version of IEEE 1366 is included.

SAIFI

Year	Raw	MED Adjusted
2013	1.22	1.19
2014	2.45	1.44
2015	1.62	1.34
2016	2.75	1.27
2017	1.85	1.14

SAIDI

Year	Raw	MED Adjusted
2013	96.30	91.31
2014	907.90	96.60
2015	154.50	96.60
2016	1390.20	90.50
2017	329.61	81.82

IEEE STANDARDS ASSOCIATION IEEE

IEEE Guide for Electric Power Distribution Reliability Indices

IEEE Power & Energy Society

Sponsored by the
Transmission and Distribution Committee

IEEE
3 Park Avenue
New York, NY 10016-5997
USA

31 May 2012

IEEE Std 1366™-2012
(Revision of
IEEE Std 1366-2003)

IEEE Std 1366™-2012
(Revision of
IEEE Std 1366-2003)

IEEE Guide for Electric Power Distribution Reliability Indices

Sponsor

Transmission and Distribution Committee
of the
IEEE Power & Energy Society

Approved 14 May 2012

IEEE-SA Standards Board

Abstract: Distribution reliability indices and factors that affect their calculations are defined in this guide. The indices are intended to apply to distribution systems, substations, circuits, and defined regions.
Keywords: circuits, distribution reliability indices, distribution systems, electric power, IEEE 1366, reliability indices

The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

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Participants

At the time this IEEE guide was completed, the Distribution Reliability Working Group had the following membership:

Rodney Robinson*, *Chair (2011-present)*
Cheryl A. Warren*, *Chair (1991-2011)*
John McDaniel*, *Vice Chair*
Val Werner, *Secretary*

John Ainscough
Razon Alvin
Daniel Arden
Greg Ardrey
Ignacio Ares
Dave Asgharian
John Banting
Philip Barker
Bill Becia
Roy Billinton
Chantal Bitton
David Blankenheim
James D. Bouford*
James Bundren
James Burke
Thomas Callsen
Mark Carr
Patrick Carroll
Heide Caswell
Bill Chisholm
Richard D. Christie*
Rob Christman
G. Larry Clark
Mike Clodfelder
James Cole
Larry Conrad
Betsy Coppock
Ed Cortez
Herve Delmas
Chuck DeNardo
Frank Doherty
April Dornbrook
R. Clay Doyle
Jeff Duff
Charlie Fijnvandratt
Fredric Friend
Keith Frost
Anish Gaikwad
David Gilmer
Manuel Gonzalez
John Goodfellow
Tom Grisham
Tom Gutwin
Donald Hall
Keith Harley
Harry Hayes
Charles Heising
Richard Hensel
James Hettrick
Ray Hisayasu
Alex Hoffman
Tao Hong
Ian Hoogendan
Mike Hyland
Cindy Janke
Allan Jirges
Joshua Jones
Robert Jones
Morteza Khodaie
Mark Koyna
Frank Lambert
Dave Lankutis
Larry Larson
Jim Lemke
Jack Leonard
Giancarlo Leone
Gene Lindholm
Ray Lings
Nick Loehlein
Ning Lu
J. C. Mathieson
Ethan Matthes
Ed Mayer
Tom McCarthy
Tom McDermott
Mark McGranaghan
Kale Meade
Tom Menten
Mathieu Mougeot
Terry Nielsen
Gregory Obenchain
Ray O'Leary
Gregory Olson
Jamie Ortega
Anil Pahwa
Milorad Papic
Marc Patterson
Dan Pearson
Mike Pehosh
Charles Perry
Ray Piercy
Jeff Pogue
Steve Pullins
Mike Rafferty
Caryn Riley
D. Tom Rizy
Tim Rogelstad
Ziolo Roldan
Robert Rusch
David Russo
D. Daniel Sabin
Robert Saint
N. D. R. Sarma
Josh Schellenberg
David J. Schepers*
Steven Schott
Andy Schwalm
Ken Sedziol
Matt Seeley
Mike Shepherd
David Shibilia
Tom Short
Cheong Siew
Georges Simard
Jeff Smith
Rusty Soderberg
John Spare
Joshua Stallings
Lee Taylor
Mark Thatcher
Casey Thompson
Betty Tobin
Tom Tobin
S. S. (Mani) Venkata
Joseph Viglietta*
Marek Waclawiak
Juli Wagner
Reigh Walling
David Wang
Daniel J. Ward
Greg Welch
Charlie Williams*
John Williams
Taui Willis
Mike Worden
Bo Yang

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James D. Bouford
Richard D. Christie
Dan Kowalewski
John McDaniel
Rodney Robinson
David J. Schepers
Joseph Viglietta
Cheryl A. Warren
Charlie Williams

The following members of the individual balloting committee voted on this guide. Balloters may have voted for approval, disapproval, or abstention.

William Ackerman
Michael Adams
Ali Al Awazi
Saleman Alibhay
Robert Arno
Thomas Basso
Wallace Binder
Robin Blanton
James D. Bouford
Gustavo Brunello
William Bush
William Byrd
Mark Carr
Robert Christman
James Cleary
James Cole
Larry Conrad
Timothy Croushore
Gary Donner
April Dornbrook
Randall Dotson
Neal Dowling
Donald Dunn
Gary Engmann
Rabiz Foda
Fredric Friend
David Gilmer
Mietek Glinkowski
Waymon Goch
Edwin Goodwin
Thomas Grebe
Randall Groves
Ajit Gwal
Donald Hall
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Jeffrey Hartenberger
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Joseph Jancauskas
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Joseph L. Koepfinger
Jim Kulchisky
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Joydeep Mitra
Jerry Murphy
Arthur Neubauer
Michael S. Newman
Joe Nims
Lorraine Padden
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Charles Rogers
Thomas Rozek
D. Daniel Sabin
Robert Saint
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Christine Siebenshuh
Cheong Siew
James Smith
Jerry Smith
John Spare
Joshua Stallings
Gary Stoedter
Lee Taylor
Mark Thatcher
Eric Udren
John Vergis
Mark Walton
Daniel J. Ward
Lee Welch
Kenneth White
Jonathan Woodworth
Jian Yu
Francisc Zavoda

Introduction

This introduction is not part of IEEE Std 1366-2012, IEEE Guide for Electric Power Distribution Reliability Indices.

This guide was originally developed in 1998 to create indices specifically designed for distribution systems. Other groups have created indices for transmission and industrial systems, but none were available for distribution. This group will continue working in this area by refining the information contained in this guide.

This guide was updated in the 2003 revision to clarify existing definitions and to introduce a statistically based definition for classification of Major Event Days. The working group created a methodology, 2.5 Beta Method, for determination of Major Event Days. Once days are classified as normal or Major Event Days, appropriate analysis and reporting can be conducted.

This 2012 revision of the guide clarified several of the definitions and introduced two new indices. The new indices are CELID-s and CELID-t, customers experiencing long interruption durations (both single and total). A section was also added to explain the investigation of catastrophic days.

Contents

IEEE Guide for Electric Power Distribution Reliability Indices

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1. Overview

1.1 Introduction

This full-use guide has been updated to clarify existing definitions, introduce two additional reliability indices, and add a discussion of Major Event Days and catastrophic days (see 5.3).

1.2 Scope

This guide identifies distribution reliability indices and factors that affect their calculation. It includes indices, which are useful today, as well as ones that may be useful in the future. The indices are intended to apply to distribution systems, substations, circuits, and defined regions.

1.3 Purpose

The purpose of this guide is twofold. First, it is to present a set of terms and definitions which can be used to foster uniformity in the development of distribution service reliability indices, to identify factors which affect the indices, and to aid in consistent reporting practices among utilities. Secondly, it is to provide guidance for new personnel in the reliability area and to provide tools for internal as well as external comparisons. In the past, other groups have defined reliability indices for transmission, generation, and distribution but some of the definitions already in use are not specific enough to be wholly adopted for distribution. Users of this guide should recognize that not all utilities would have the data available to calculate all the indices.

2. Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary: Glossary of Terms and Definitions*[1] should be consulted for terms not defined in this clause.

connected load: Connected transformer or metered demand (to be clearly specified when reporting) on the circuit or portion of circuit that is interrupted. When reporting, the report should state whether it is based on an annual peak or on a reporting period peak.

customer: A metered electrical service point for which an active bill account is established at a specific location.

customer count: The number of customers either served or interrupted, depending on usage.

distribution system: That portion of an electric system that delivers electric energy from transformation points on the transmission system to the customer.

NOTE—The distribution system is generally considered to be anything from the distribution substation fence to the customer meter. Often the initial overcurrent protection and voltage regulators are within the substation fence and are considered part of the distribution system.[2]

forced outage: The state of a component when it is not available to perform its intended function due to an unplanned event directly associated with that component.

interrupting device: A device to stop the flow of power, usually in response to a fault. Operation of the device can be accomplished by manual, automatic, or remotely operated methods. Examples include circuit breakers, line reclosers, line fuses, disconnect switches, sectionalizers, and/or others.

interruption: The total loss of electric power on one or more normally energized conductors to one or more customers connected to the distribution portion of the system. This does not include any of the power quality issues such as: sags, swells, impulses, or harmonics. *See also:* **outage.**

interruption duration: The time period from the initiation of an interruption until service has been restored to the affected customers.

NOTE—The process of restoration may require restoring service to small sections of the system until service has been restored to all customers. See 4.3.2 for a step-restoration example. Each of these individual steps should be tracked, collecting the start time, end time, and number of customers interrupted for each step.

interruptions caused by events outside of the distribution system: Outages that occur on generation, transmission, substations, or customer facilities that result in the interruption of service to one or more customers. While generally a small portion of the number of interruption events, these interruptions can affect a large number of customers and may last for a long time.

lockout: When a reclosing interrupting device is in the open position and no further operations of that device are allowed without manual intervention.

[1] *IEEE Standards Dictionary: Glossary of Terms and Definitions* is available at http://shop.ieee.org.
[2] Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

Major Event: Designates an event that exceeds reasonable design and or operational limits of the electric power system. A Major Event includes at least one Major Event Day. *See also:* **Major Event Day.**

Major Event Day (MED): A day in which the daily system System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold value. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as during severe weather). Activities that occur on Major Event Days should be separately analyzed and reported.

NOTE—See Major Event Day classification in 3.5.

momentary interruption: The brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device.

NOTE—Two circuit breaker or recloser operations (each operation being an open followed by a close) that briefly interrupt service to one or more customers are defined as two momentary interruptions.

momentary interruption event: An interruption of duration limited to the period required to restore service by an interrupting device.

NOTE 1—Such switching operations must be completed within a specified time of five minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption.

NOTE 2—If a recloser or circuit breaker operates two, three, or four times and then holds (within five minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event.

outage: The loss of ability of a component to deliver power.

NOTE 1—An outage may or may not cause an interruption of service to customers, depending on system configuration.

NOTE 2—This definition derives from transmission and distribution applications and does not apply to generation outages.

planned interruption: The loss of electric power to one or more customers that results from a planned outage.

NOTE 1—This derives from transmission and distribution applications and does not apply to generation interruptions.

NOTE 2—The key test to determine if an interruption should be classified as a planned or unplanned interruption is as follows: If it is possible to defer the interruption, then the interruption is a planned interruption; otherwise, the interruption is an unplanned interruption.

planned outage: The intentional disabling of a component's capability to deliver power, done at a preselected time, usually for the purposes of construction, preventative maintenance, or repair.

reporting period: The time period from which interruption data is to be included in reliability index calculations. The beginning and end dates and times should be clearly indicated. All events that begin within the indicated time period should be included. A consistent reporting period should be used when comparing the performance of different distribution systems (typically one calendar year) or when comparing the performance of a single distribution system over an extended period of time. The reporting period is assumed to be one year, unless otherwise stated.

step restoration: The process of restoring all interrupted customers in stages over time.

sustained interruption: Any interruption not classified as a part of a momentary event. That is, any interruption that lasts more than five minutes.

total number of customers served: The average number of customers served during the reporting period. If a different customer total is used, it must be clearly defined within the report.

unplanned interruption: The loss of electric power to one or more customers that does not result from a planned outage.

3. Definitions of reliability indices

3.1 Basic factors

The basic factors defined below specify the data needed to calculate the reliability indices.

NOTE—The subscript 'i' denotes an interruption event.

CI	Customers interrupted
CMI	Customer minutes of interruption
CN	Total number of distinct customers who have experienced a sustained interruption during the reporting period
$\mathbf{CN}_{(k\geq n)}$	Total number of customers who have experienced n or more sustained interruptions during the reporting period
$\mathbf{CN}_{(k\geq S)}$	Total number of customers that experienced S or more hours duration
$\mathbf{CN}_{(k\geq T)}$	Total number of customers that experienced T or more hours duration
$\mathbf{CNT}_{(k\geq n)}$	Total number of customers who have experienced n or more sustained interruptions and momentary interruption events during the reporting period
E	Event
$\mathbf{IM}_i$	Number of momentary interruptions
$\mathbf{IM}_E$	Number of momentary interruption events
k	Number of interruptions experienced by an individual customer in the reporting period
$\mathbf{L}_i$	Connected kVA load interrupted for each interruption event
$\mathbf{L}_T$	Total connected kVA load served
$\mathbf{N}_i$	Number of interrupted customers for each sustained interruption event during the reporting period
$\mathbf{N}_{mi}$	Number of interrupted customers for each momentary interruption event during the reporting period

N_T Total number of customers served for the area

r_i Restoration time for each interruption event

T_{MED} Major Event Day threshold

3.2 Sustained interruption indices

3.2.1 SAIFI: System Average Interruption Frequency Index

The System Average Interruption Frequency Index (SAIFI) indicates how often the average customer experiences a sustained interruption over a predefined period of time. Mathematically, this is given in Eq. (1).

$$\mathrm{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}} \tag{1}$$

To calculate the index, use Eq. (2).

$$\mathrm{SAIFI} = \frac{\sum N_i}{N_T} = \frac{CI}{N_T} \tag{2}$$

3.2.2 SAIDI: System Average Interruption Duration Index

The System Average Interruption Duration Index (SAIDI) indicates the total duration of interruption for the average customer during a predefined period of time. It is commonly measured in minutes or hours of interruption. Mathematically, this is given in Eq. (3).

$$\mathrm{SAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Served}} \tag{3}$$

To calculate the index, use Eq. (4).

$$\mathrm{SAIDI} = \frac{\sum r_i N_i}{N_T} = \frac{CMI}{N_T} \tag{4}$$

3.2.3 CAIDI: Customer Average Interruption Duration Index

The Customer Average Interruption Duration Index (CAIDI) represents the average time required to restore service. Mathematically, this is given in Eq. (5).

$$\mathrm{CAIDI} = \frac{\sum \text{Customer Minutes of Interruption}}{\text{Total Number of Customers Interrupted}} = \frac{CMI}{CI} \tag{5}$$

To calculate the index, use Eq. (6).

$$\mathrm{CAIDI} = \frac{\Sigma r_i N_i}{\Sigma N_i} = \frac{\mathrm{SAIDI}}{\mathrm{SAIFI}} \tag{6}$$

3.2.4 CTAIDI: Customer Total Average Interruption Duration Index

The Customer Total Average Interruption Duration Index (CTAIDI) represents the total time in the reporting period that average customers who actually experienced an interruption were without power. This index is a hybrid of CAIDI and is similarly calculated, except that those customers with multiple interruptions are counted only once. Mathematically, this is given in Eq. (7).

$$\mathrm{CTAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Distinct Customers Interrupted}} \tag{7}$$

To calculate the index, use Eq. (8).

$$\mathrm{CTAIDI} = \frac{\Sigma r_i N_i}{\mathrm{CN}} = \frac{CMI}{CN} \tag{8}$$

NOTE—In tallying Total Number of Customers Interrupted, each individual customer should be counted only once regardless of the number of times interrupted during the reporting period. This applies to definitions provided in 3.2.4 and 3.2.5.

3.2.5 CAIFI: Customer Average Interruption Frequency Index

The Customer Average Interruption Frequency Index (CAIFI) gives the average frequency of sustained interruptions for those customers experiencing sustained interruptions. The customer is counted once, regardless of the number of times interrupted for this calculation. Mathematically, this is given in Eq. (9).

$$\mathrm{CAIFI} = \frac{\sum \text{Total Number of Customer Interruptions}}{\text{Total Number of Distinct Customers Interrupted}} \tag{9}$$

To calculate the index, use Eq. (10).

$$\mathrm{CAIFI} = \frac{\Sigma N_i}{\mathrm{CN}} = \frac{CI}{CN} \tag{10}$$

3.2.6 ASAI: Average Service Availability Index

The Average Service Availability Index (ASAI) represents the fraction of time (often in percentage) that a customer has received power during the defined reporting period. Mathematically, this is given in Eq. (11).

$$\mathrm{ASAI} = \frac{\text{Customer Hours Service Availability}}{\text{Customer Hours Service Demand}} \tag{11}$$

To calculate the index, use Eq. (12).

$$\mathrm{ASAI} = \frac{N_T \times (\text{Number of hours/yr}) - \sum r_i N_i}{N_T \times (\text{Number of hours/yr})} \tag{12}$$

NOTE—There are 8 760 hours in a non-leap year and 8 784 hours in a leap year.

3.2.7 CEMI$_n$: Customers Experiencing Multiple Interruptions

The Customers Experiencing Multiple Interruptions Index (CEMI$_n$) indicates the ratio of individual customers experiencing n or more sustained interruptions to the total number of customers served. Mathematically, this is given in Eq. (13).

$$\mathrm{CEMI}_n = \frac{\text{Total Number of Customers that experienced n or more sustained interruptions}}{\text{Total Number of Customers Served}} \tag{13}$$

To calculate the index, use Eq. (14).

$$\mathrm{CEMI}_n = \frac{CN_{(k \geq n)}}{N_T} \tag{14}$$

NOTE—This index is often used in a series of calculations with n incremented from a value of 1 to the highest value of interest.

3.2.8 CELID: Customers Experiencing Long Interruption Durations

The Customers Experiencing Long Interruption Durations Index (CELID) indicates the ratio of individual customers that experience interruptions with durations longer than or equal to a given time. That time is either the duration of a single interruption (s) or the total amount of time (t) that a customer has been interrupted during the reporting period. Mathematically, the Single Interruption Duration equation is given in Eq. (15) and the Total Interruption Duration equation is given in Eq. (17).

Single Interruption Duration:

$$\text{CELID-t} = \frac{\text{Total Number of Customers that experienced S or more hours duration}}{\text{Total Number of Customers Served}} \tag{15}$$

To calculate the index, use Eq. (16).

$$\text{CELID-s} = \frac{CN_{(k \geq S)}}{N_T} \tag{16}$$

Total Interruption Duration:

$$\text{CELID-t} = \frac{\text{Total Number of Customers that experienced T or more hours duration}}{\text{Total Number of Customers Served}} \tag{17}$$

To calculate the index, use Eq. (18).

$$\text{CELID-t} = \frac{CN_{(k \geq T)}}{N_T} \tag{18}$$

3.3 Load based indices

3.3.1 ASIFI: Average System Interruption Frequency Index

The calculation of the Average System Interruption Frequency Index (ASIFI) is based on load rather than customers affected. ASIFI is sometimes used to measure distribution performance in areas that serve relatively few customers that have relatively large concentrations of load, predominantly industrial/commercial customers. Theoretically, in a system with homogeneous load distribution, ASIFI would be the same as SAIFI. Mathematically, this ASIFI is given in Eq. (19).

$$\text{ASIFI} = \frac{\sum \text{Total Connected kVA of Load Interrupted}}{\text{Total Connected kVA Served}} \tag{19}$$

To calculate the index, use Eq. (20).

$$\text{ASIFI} = \frac{\sum L_i}{L_T} \tag{20}$$

3.3.2 ASIDI: Average System Interruption Duration Index

The calculation of the Average System Interruption Duration Index (ASIDI) is based on load rather than customers affected. Its use, limitations, and philosophy are stated in the ASIFI definition in 3.3.1. Mathematically, ASIDI is given in Eq. (21).

$$\text{ASIDI} = \frac{\sum \text{Connected kVA Duration of Load Interrupted}}{\text{Total Connected kVA Served}} \tag{21}$$

To calculate the index, use Eq. (22).

$$\text{ASIDI} = \frac{\sum r_i L_i}{L_T} \tag{22}$$

3.4 Other indices (momentary)

3.4.1 MAIFI: Momentary Average Interruption Frequency Index

The Momentary Average Interruption Frequency Index (MAIFI) indicates the average frequency of momentary interruptions. Mathematically, this is given in Eq. (23).

$$\mathrm{MAIFI} = \frac{\sum \text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}} \tag{23}$$

To calculate the index, use Eq. (24).

$$\mathrm{MAIFI} = \frac{\sum IM_i N_{mi}}{N_T} \tag{24}$$

3.4.2 MAIFI$_E$: Momentary Average Interruption Event Frequency Index

The Momentary Average Interruption Event Frequency Index (MAIFI$_E$) indicates the average frequency of momentary interruption events. This index does not include the events immediately preceding a sustained interruption. Mathematically, this is given in Eq. (25).

$$\mathrm{MAIFI_E} = \frac{\sum \text{Total Number of Customer Momentary Interruption Events}}{\text{Total Number of Customers Served}} \tag{25}$$

To calculate the index, use Eq. (26).

$$\mathrm{MAIFI_E} = \frac{\sum IM_E N_{mi}}{N_T} \tag{26}$$

3.4.3 CEMSMI$_n$: Customers Experiencing Multiple Sustained Interruption and Momentary Interruption Events

The Customers Experiencing Multiple Sustained Interruption and Momentary Interruption Events Index (CEMSMI$_n$) is the ratio of individual customers experiencing *n* or more of both sustained interruptions and momentary interruption events to the total customers served. Its purpose is to help identify customer issues that cannot be observed by using averages. Mathematically, this is given in Eq. (27).

$$\mathrm{CEMSMI}_n = \frac{\text{Total Number of Customers Experiencing n or More Interruptions}}{\text{Total Number of Customers Served}} \tag{27}$$

To calculate the index, use Eq. (28).

$$\mathrm{CEMSMI}_n = \frac{CNT_{(k \geq n)}}{N_T} \tag{28}$$

3.5 Major Event Day classification

The following process—Beta Method—is used to identify Major Event Days (MED), provided that the natural log transformation of the data results closely resembles a Gaussian (normal) distribution. Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events. For more technical detail on derivation of the methodology, refer to Annex B.

A MED is a day in which the daily system SAIDI exceeds a threshold value, T_{MED}. The SAIDI index is used as the basis of this definition since it leads to consistent results regardless of utility size, and because SAIDI is a good indicator of operational and design stress. Even though SAIDI is used to determine the MEDs, all indices should be calculated based on removal of the identified days.

In calculating daily system SAIDI, any interruption that spans multiple days is accrued to the day on which the interruption begins.

The MED identification T_{MED} value is calculated at the end of each reporting period (typically one year) for use during the next reporting period, as follows:

a) Collect values of daily SAIDI for five sequential years, ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all available historical data until five years of historical data are available.

b) Only those days that have a SAIDI/Day value will be used to calculate T_{MED} (do not include days that did not have any interruptions).

c) Take the natural logarithm (ln) of each daily SAIDI value in the data set.

d) Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.

e) Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.

f) Compute the MED threshold, T_{MED}, using Eq. (29).

$$T_{MED} = e^{(\alpha+2.5\beta)} \tag{29}$$

g) Any day with daily SAIDI greater than the threshold value T_{MED} that occurs during the subsequent reporting period is classified as a MED.

Activities that occur on days classified as MEDs should be separately analyzed and reported.

3.5.1 An example of using the MED definition to identify major events and subsequently calculate adjusted indices that reflect normal operating performance

The following example illustrates the calculation of the daily SAIDI, calculation of the MED threshold T_{MED}, identification of MEDs, and calculation of adjusted indices.

Table 1 gives selected data for all interruptions occurring on a certain day for a utility that serves 2 000 customers.

Table 1—Interruption data for March 18, 1994

Date	Time	Duration (min)	Number of customers	Interruption Type
Mar 18, 1994	18:34:30	20.0	200	Sustained
Mar 18, 1994	18:38:30	1.0	400	Momentary
Mar 18, 1994	18:42:00	513.5	700	Sustained

Note that although the third interruption (at 18:42:00) was not restored until the following day, its total duration counts in the day that the interruption began. Note also that SAIDI considers only sustained interruptions.

For March 18, 1994, daily SAIDI (assuming a 2 000 customer utility) is given in Eq. (30).

$$\mathrm{SAIDI} = \frac{(20\times 200)+(513.5\times 700)}{2000} = 181.73\ \mathrm{min} \qquad (30)$$

One month of historical daily SAIDI data is used in the following example to calculate the MED threshold T_{MED}. Five years of historical data is preferable for this method, but printing that many values in this guide is impractical, so only one month is used to illustrate the concept. The example data is shown in Table 2.

Table 2—One month of daily SAIDI and ln(SAIDI/day) data

Date	SAIDI/day (min)	ln(SAIDI/day)	Date	SAIDI/day (min)	ln(SAIDI/day)
Dec 1, 1993	26.974	3.295	Dec 17, 1993	0.329	-1.112
Dec 2, 1993	0.956	-0.046	Dec 18, 1993	0	This day is not included in the calculations since no customers were interrupted.
Dec 3, 1993	0.131	-2.033	Dec 19, 1993	0.281	-1.268
Dec 4, 1993	1.292	0.256	Dec 20, 1993	1.810	0.593
Dec 5, 1993	4.250	1.447	Dec 21, 1993	0.250	-1.388
Dec 6, 1993	0.119	-2.127	Dec 22, 1993	0.021	-3.876
Dec 7, 1993	0.130	-2.042	Dec 23, 1993	1.233	0.209
Dec 8, 1993	12.883	2.556	Dec 24, 1993	0.996	-0.004
Dec 9, 1993	0.226	-1.487	Dec 25, 1993	0.162	-1.818
Dec 10, 1993	13.864	2.629	Dec 26, 1993	0.288	-1.244
Dec 11, 1993	0.015	-4.232	Dec 27, 1993	0.535	-0.626
Dec 12, 1993	1.788	0.581	Dec 28, 1993	0.291	-1.234
Dec 13, 1993	0.410	-0.891	Dec 29, 1993	0.600	-0.511
Dec 14, 1993	0.007	-4.967	Dec 30, 1993	1.750	0.560
Dec 15, 1993	1.124	0.117	Dec 31, 1993	3.622	1.287
Dec 16, 1993	1.951	0.668			

NOTE—The SAIDI/day for December 18, 1993 is zero, and the natural logarithm of zero is undefined. Therefore, December 18, 1993 is not considered during the analysis.

The value of α, the log-average, is the average of the natural logs, and equals -0.555 in this case.

The value of β, the log-standard deviation, is the standard deviation of the natural logs, and equals 1.90 in this example.

The value of $\alpha + 2.5\beta$ is 4.20.

The threshold value T_{MED} is calculated by $e^{(4.20)}$ and equals 66.69 SAIDI minutes per day. This value is used to evaluate the future time period (e.g., the next year).

Table 3 shows example SAIDI/day values for the first month of 1994.

Table 3—Daily SAIDI data, January 1994

Date	SAIDI/Day	Date	SAIDI/Day
Jan 1, 1994	0.240	Jan 17 1994	5.700
Jan 2, 1994	0.014	Jan 18, 1994	0.109
Jan 3, 1994	0.075	Jan 19, 1994	0.259
Jan 4, 1994	2.649	Jan 20, 1994	1.142
Jan 5, 1994	0.666	Jan 21, 1994	0.262
Jan 6, 1994	0.189	Jan 22, 1994	0.044
Jan 7, 1994	0.009	Jan 23, 1994	0.243
Jan 8, 1994	1.117	Jan 24, 1994	5.932
Jan 9, 1994	0.111	Jan 25, 1994	2.698
Jan 10, 1994	8.683	Jan 26, 1994	5.894
Jan 11, 1994	0.277	Jan 27, 1994	0.408
Jan 12, 1994	0.057	Jan 28, 1994	237.493
Jan 13, 1994	0.974	Jan 29, 1994	2.730
Jan 14, 1994	0.150	Jan 30, 1994	8.110
Jan 15, 1994	0.633	Jan 31, 1994	0.046
Jan 16, 1994	0.434		

The SAIDI/day on January 28, 1994 (237.49) exceeds the example threshold value (T_{MED} = 66.69), indicating that the distribution system experienced stresses beyond that normally expected on that day. Therefore, January 28, 1994 is classified as a MED. The SAIDI/day for all other days was less than T_{MED}, indicating that normal stresses were experienced on those days.

To complete the example, indices should be calculated for two conditions:

1) All events included
2) MEDs removed

In most cases, utilities will calculate all of the indices they normally use (e.g., SAIFI, SAIDI, and/or CAIDI). For this example, only SAIDI will be shown. The SAIDI for 1994 for condition 1) above (all events included) is given in Eq. 31.

$$\text{SAIDI} = \sum \text{Daily SAIDI} = 287.35 \tag{31}$$

The SAIDI for 1994 for condition 2) above (MEDs removed), for separate reporting and analysis, is given in Eq. 32.

$$\text{SAIDI} = \sum \text{Daily SAIDI with the MEDs removed} = 49.86 \tag{32}$$

4. Application of the indices

Most utilities store interruption data in large computer databases. Some databases are better organized than others for querying and analyzing reliability data. The following subclause will show one sample partial database and the methodology for calculating indices based on the information provided.

4.1 Sample system

Table 4 shows an excerpt from one utility's customer information system (CIS) database for feeder 7075, which serves 2 000 customers with a total load of 4 MW. In this example, Circuit 7075 constitutes the "system" for which the indices are calculated. More typically, the "system" combines all circuits together in a region or for a whole company.

Table 4—Interruption data for 1994

Date	Time	Time on	Circuit	Event code	Number of customers	Load kVA	Interruption type
Mar 17	12:12:20	12:20:30	7075	107	200	800	S
Apr 15	18:23:56	18:24:26	7075	256	400	1 600	M
May 5	00:23:10	01:34:29	7075	435	600	1 800	S
Jun 12	23:17:00	23:47:14	7075	567	25	75	S
Jul 6	09:30:10	09:31:10	7075	678	2 000	4 000	M
Aug 20	15:45:39	20:12:50	7075	832	90	500	S
Aug 31	08:20:00	10:20:00	7075	1 003	700	2 100	S
Sep 3	17:10:00	17:20:00	7075	1 100	1 500	3 000	S
Oct 27	10:15:00	10:55:00	7075	1 356	100	200	S

NOTE 1—Interruption type S = sustained; M = momentary

NOTE 2—Total customers served = 2 000

The total number of customers who have experienced a sustained interruption is 3 215. The total number of customers experiencing a momentary interruption is 2 400.

Table 5—Extracted customers who were interrupted

Name	Circuit number	Date	Event code	Duration (min)
Willis, J.	7075	Mar 17, 1994	107	8.17
Williams, J.	7075	Apr 15, 1994	256	0.5
Willis, J.	7075	Apr 15, 1994	256	0.5
Wilson, D.	7075	May 5, 1994	435	71.3
Willis, J.	7075	Jun 12, 1994	567	30.3
Willis, J.	7075	Aug 20, 1994	832	267.2
Wilson, D.	7075	Aug 20, 1994	832	267.2
Yattaw, S.	7075	Aug 20, 1994	832	267.2
Willis, J.	7075	Aug 31, 1994	1003	120
Willis, J.	7075	Sep 3, 1994	1100	10
Willis, J.	7075	Oct 27, 1994	1356	40

Table 6—Interruption device operations

Record number	Device	Date	Time	Number of operations	Number of operations to lockout
1	Brk 7075	Apr 15	18:23:56	2	3
2	Recl 7075	Jul 6	09:30:10	3	4
3	Brk 7075	Aug 2	12:29:02	1	3
4	Brk 7075	Aug 2	12:30:50	2	3
5	Recl 7075	Aug 2	13:25:40	2	4
6	Recl 7075	Aug 25	08:00:00	2	4
7	Brk 7075	Sep 2	04:06:53	2	3
8	Recl 7075	Sep 5	11:53:22	3	4
9	Brk 7075	Sep 8	15:25:10	1	3
10	Recl 7075	Oct 2	17:15:19	1	4
11	Recl 7075	Nov 12	00:00:05	1	4

From Table 6, it can be seen that there were eight circuit breaker operations that affected 2 000 customers. Each of them experienced eight momentary interruptions. There were 12 recloser operations that caused 750 customers to experience 12 momentary interruptions. Some of the operations occurred during one reclosing sequence. To calculate the number of momentary interruption events, count only the total number of reclosing sequences. In this case, there were five circuit breaker events (records 1, 3, 4, 7, and 9) that affected 2 000 customers. Each of them experienced five momentary interruption events. There were six recloser events (records 2, 5, 6, 8, 10, and 11) that affected 750 customers, and each of them experienced six momentary interruption events.

4.2 Calculation of indices for a system with no Major Event Days

The equations in 3.5, and definitions in Clause 2, should be used to calculate the annual indices (see Eq. (33) through Eq. (46), below). In the example below, the indices are calculated by using the equations in 3.2 and 3.4 using the data in Table 4 and Table 5, assuming there were no MEDs in this data set:

$$\mathrm{SAIFI} = \frac{200 + 600 + 25 + 90 + 700 + 1500 + 100}{2000} = 1.61 \tag{33}$$

$$\mathrm{SAIDI} = \frac{(8.17\times 200)+(71.3\times 600)+(30.3\times 25)+(267.2\times 90)+(120\times 700)+(10\times 1500)+(40\times 100)}{2000} = 86.11\ \mathrm{min} \tag{34}$$

$$\mathrm{CAIDI} = \frac{\mathrm{SAIDI}}{\mathrm{SAIFI}} = \frac{86.110}{1.6075} = 53.57\mathrm{min} \tag{35}$$

To calculate CTAIDI and CAIFI, the number of customers experiencing a sustained interruption is required. The total number of customers affected (CN) for this example can be no more than 2 000. Since only a small portion of the customer information table is shown, it is impossible to know CN; however, it is likely that not all of the 2 000 customers on this feeder experienced an interruption during the year. An arbitrary number of customers, 1 800, will be assumed for CN (for your calculations, actual information should be used) since the interruption on September 3 shows that at least 1 500 customers have been interrupted during the year.

$$\mathrm{CTAIDI} = \frac{(8.17\times200)+(71.3\times600)+(30.3\times25)+(267.2\times90)+(120\times700)+(10\times1500)+(40\times100)}{1800} = 95.68\,\mathrm{min} \tag{36}$$

$$\mathrm{CAIFI} = \frac{200+600+25+90+700+1500+100}{1800} = 1.79 \tag{37}$$

$$\mathrm{ASAI} = \frac{8760\times2000-(8.17\times200+600\times71.3+30.3\times25+267.2\times90+120\times700+10\times700+10\times1500+40\times100)/60}{8760\times2000} = 0.999836 \tag{38}$$

$$\mathrm{ASIFI} = \frac{800+1800+75+500+2100+3000+200}{4000} = 2.12 \tag{39}$$

$$\mathrm{ASIDI} = \frac{(800\times8.17)+(1800\times71.3)+(75\times30.3)+(500\times267.2)+(2100\times700)+3000(6)+200\times40}{4000} = 444.69 \tag{40}$$

CTAIDI, CAIFI, CEMI_n, CELID-s, CELID-t, and CEMSMI_n require detailed interruption information for each customer. The database should be searched for all customers who have experienced more than *n* interruptions that last longer than five minutes. Assume *n* is chosen to be five. In Table 5, customer J. Willis experienced seven interruptions in one year, and it is plausible that other customers also experienced more than five interruptions, both momentary and sustained.

For this example, assume arbitrary values of 350 for $CN_{(k\geq n)}$, 90 for $CN_{(k\geq S)}$, 40 for $CN_{(k\geq T)}$, and 750 for $CNT_{(k\geq n)}$. The number of interrupting device operations is given in Table 6 and is used to calculate MAIFI and MAIFI_E. Assume the number of customers downstream of the recloser equals 750. These numbers would be known in a real system.

$$\mathrm{CEMI}_5 = \frac{350}{2000} = 0.175 \tag{41}$$

$$\text{CELID-s}(4) = \frac{90}{2000} = 0.045 \tag{42}$$

$$\text{CELID-t}(6) = \frac{40}{2000} = 0.02 \tag{43}$$

$$\mathrm{MAIFI} = \frac{8\times2000+12\times750}{2000} = 12.5 \tag{44}$$

$$\mathrm{MAIFI}_E = \frac{5\times2000+6\times750}{2000} = 7.25 \tag{45}$$

$$\mathrm{CEMSMI}_5 = \frac{750}{2000} = 0.375 \tag{46}$$

Using the above sample system should help define the methodology and approach to obtaining data from the information systems and help calculate the indices.

4.3 Examples

This subclause illustrates two concepts—momentary interruptions and step restoration—through the use of examples.

4.3.1 Momentary interruption example

To better illustrate the concepts of momentary interruptions and sustained interruptions and the associated indices, consider Figure 1 and Eq. (45) through Eq. (47). Figure 1 illustrates a circuit composed of a circuit breaker (B), a recloser (R), and a sectionalizer (S).

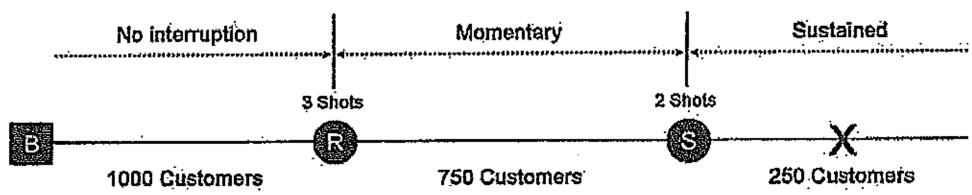

Figure 1—Sample system two

For this scenario, 750 customers would experience a momentary interruption event (two momentary interruptions), and 250 customers would experience a sustained interruption. Calculations for SAIFI, MAIFI, and $MAIFI_E$ on a feeder basis are shown in Eq. (47) through Eq. (49) below. Notice that the numerator of MAIFI is multiplied by two because the recloser took two shots, however, $MAIFI_E$ is multiplied by one because it counts only the fact that a series of momentary events occurred.

$$SAIFI = \frac{250}{2000} = 0.125 \tag{47}$$

$$MAIFI = \frac{2 \times 750}{2000} = 0.75 \tag{48}$$

$$MAIFI_E = \frac{1 \times 750}{2000} = 0.375 \tag{49}$$

4.3.2 Step restoration example

The following case illustrates the step restoration process. A feeder serving 1 000 customers experiences a sustained interruption. Multiple restoration steps are required to restore service to all customers. Table 7 shows the times of each step, a description and associated customers interrupted, and minutes they were affected in a timeline format.

Table 7—Example for a feeder serving 1 000 customers with a sustained interruption

Time from initial fault (min)	Description	Customers remaining interrupted	Customers restored
—	The initial fault occurs, the feeder breaker opens, and all 1 000 customers are interrupted. Switches are opened along the feeder.	1 000	—
45	The feeder breaker is closed, but only 500 customers are restored.	500	500
60	Through closing a switch, an additional 300 customers are restored.	200	800
70	An additional incident occurs which causes the feeder breaker to open, interrupting the 800 customers previously restored.	1 000	—
90	The feeder breaker is closed, and restores 800 customers.	200	800
120	Permanent repairs are completed and the remaining 200 customers are restored. The outage event is concluded.	—	1 000
Totals		N/A	1 800

Figure 2 illustrates the example described in Table 7. Note that both the block of 500 customers and the block of 300 customers experience two interruptions during this event.

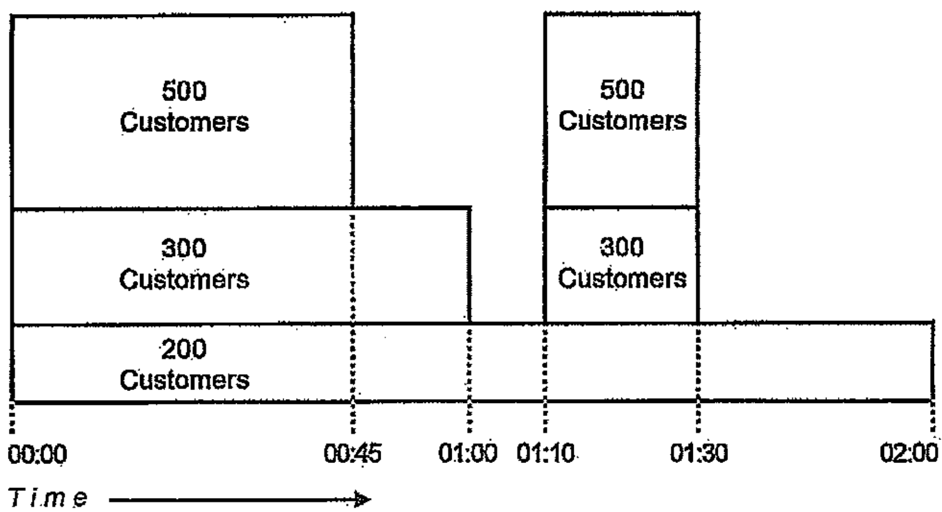

Figure 2—Step restoration time chart

Table 8 enumerates the CI and CMI for the example.

Table 8—Restoration steps for the example

Time	Interruption duration (min)	CI	CMI
00:00-00:45	45	500	22 500
00:00-01:00	60	300	18 000
01:10-01:30	20	800	16 000
00:00-02:00	120	200	24 000
	Total	1 800	80 500

Example SAIFI = 1 800/1 000 = 1.8 interruptions

Example CAIDI = 80 500/1 800 = 44.7 min

Example SAIDI = 80 500/1 000 = 80.5 min

5. Information about the factors that affect the calculation of reliability indices

5.1 Rationale behind selecting the indices provided in this guide

One view of distribution system performance can be garnered through the use of reliability indices. To adequately measure performance, both duration and frequency of customer interruptions must be examined at various system levels. The most commonly used indices are SAIFI, SAIDI, CAIDI, and ASAI, which all provide information about average system performance. Many utilities also calculate indices on a feeder basis to provide more detailed information for decision making. Averages give general performance trends for the utility; however, using averages will lead to loss of detail that could be critical to decision making. For example, using system averages alone will not provide information about the interruption duration experienced by any specific customer. It is difficult for most utilities to provide information on a customer basis. This group believes the tracking of specific details surrounding interruptions, rather than averages, may be accomplished by improving tracking capabilities. To this end, the working group has included not only the most commonly used indices, but also indices that examine performance at the customer level (e.g., $CEMI_n$ and the CELIDs).

5.2 Factors that cause variation in reported indices

Many factors can cause variation in the indices reported by different utilities. Some examples are differences in:

— Level of automated data collection

— Geography

— System design

— Data classification (e.g., Are major events in the data set? Planned interruptions?)

To ensure accurate and equitable assessment and comparison of absolute performance and performance trends over time, it is important to classify performance for each day in the data set to be analyzed as either day-to-day or MED. Not performing this critical step can lead to false decision making because MED performance often overshadows and disguises daily performance. Interruptions that occur as a result of outages on customer-owned facilities, or loss of supply from another utility, should not be included in the index calculation.

5.3 Major Event Days and catastrophic days

When using daily SAIDI and the 2.5β method, there is an assumption that the distribution of the natural log values will most likely resemble a Gaussian distribution, namely a bell-shaped curve. As companies have used this method, a certain number of them have experienced large-scale events (such as hurricanes or ice storms) that result in unusually sizable daily SAIDI values. The events that give rise to these particular days, considered "catastrophic events," have a low probability of occurring. However, the extremely large daily SAIDI values may tend to skew the distribution of performance toward the right, causing a shift of the average of the data set and an increase in its standard deviation. Large daily SAIDI values caused by catastrophic events will exist in the data set for five years and could cause a relatively minor upward shift in the resulting reliability metric trends. While significant study was undertaken to develop objective methods for identifying and processing catastrophic events (in order to eliminate the noted effect on the reliability trend), the methods that were developed, in order to be universally applied, caused for many utilities, catastrophic events to occur far too often to accept as being reasonable. In addition, the elimination of catastrophic events from the calculation of the major event threshold caused, in some utilities, a rather large increase of days identified as MEDs in the following five years. It is recommended that the identification and processing of catastrophic events for reliability purposes should be determined on an individual company basis by regulators and utilities since no objective method has been devised that can be applied universally to achieve acceptable results.

Annex A

(informative)

Bibliography

Bibliographical references are resources that provide additional or helpful material but do not need to be understood or used to implement this standard. Reference to these resources is made for informational use only.

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Annex B

(informative)

Major event definition development

B.1 Justification and process for development of the 2.5 β methodology

A statistical approach to identifying MEDs was chosen over the previous definitions because of the difficulties experienced in creating a uniform list of types of major events, and because the measure of impact criterion (i.e., percent of customers affected) required when using event types resulted in non-uniform identification. The statistical methodology should more fairly identify major events for all utilities. Some key issues had to be addressed in order to consider this work successful. These issues include:

- Definition must be understandable and easy to apply.
- Definition must be specific and calculated using the same process for all utilities.
- Must be fair to all utilities regardless of size, geography, or design.
- Entities that adopt the methodology will calculate indices on a normalized basis for trending and reporting. They will further classify the MEDs separately and report on those days through a separate process.

Daily SAIDI values are preferred to daily Customer Minutes of Interruption (CMI) values for MED identification because the former permits comparison and computation among years with different numbers of customers served. Consider the merger of two utilities with the same reliability and the same number of customers. CMI after the merger would double, with no change in reliability, while SAIDI would stay constant.

Daily SAIDI values are preferred to daily SAIFI values because SAIDI values are a better measure of the total cost of reliability events, including utility repair costs and customer losses. The total cost of unreliability would be a better measure of the size of a major event, but collection of this data is not practical.

The selected approach for setting the MED identification threshold, known as the "Two Point Five Beta" (2.5β) method (since it is using the log-normal SAIDI values rather than the raw SAIDI values), is preferred to using fixed multiples of standard deviation (e.g., "Three Sigma") to set the identification threshold because the former results in more uniform MED identification among utilities with different sizes and average reliabilities. The β multiplier of 2.5 was chosen because, in theory, it would classify 2.3 days per year as major events. If significantly more days than this are identified, they represent events that have occurred outside the random process that is assumed to control distribution system reliability. The process and the multiplier value were evaluated by a number of utilities with different sized systems from different parts of the United States and found to correlate reasonably well to current major event identification results for those utilities. A number of alternative approaches were considered. None was found to be clearly superior to the 2.5β method.

When a major event occurs that lasts through midnight (for example, a six hour hurricane which starts at 9:00 p.m.), the reliability impact of the event may be split between two days, neither of which would exceed the T_{MED} and therefore be classified as a MED. This is a known inaccuracy in the method, which is accepted in exchange for the simplicity and ease of calculation of the method. The preferred number of years of data (five) used to calculate the MED identification threshold was set by trading off between the desire to reduce statistical variation in the threshold (for which more data is better) and the desire to see the effects of changes in reliability practices in the reported results, and to limit the amount of data which must be archived.

B.1.1 Remarks

To generate the example data used in 3.5.1, values of α and β were taken from an actual utility data set, and then daily SAIDI/day values were artificially generated using a log normal distribution with these values of α and β. The daily SAIDI values were then adjusted to illustrate all aspects of the calculation (e.g., a day in Table 2 was assigned a SAIDI value of zero, and a day in Table 3 was assigned a SAIDI value higher than the computed threshold).

This annex provides a technical description and analysis of the 2.5β method of identifying MEDs in distribution reliability data. The 2.5β method is a statistical method based on the theory of probability and statistics. Fundamental concepts such as *probability distribution* and *expected value* are highlighted in italics when they are first used and provided with a short definition. An undergraduate probability and statistics textbook can be consulted for definitions that are more complete.

B.2 2.5β method description

See 3.5 of this guide for the detailed procedure for identifying MEDs. The short version is presented here. A threshold on daily SAIDI is computed once a year as follows:

a) Assemble the five most recent years of historical values of SAIDI/day. If less than five years of data is available, use as much as is available.

b) Discard any day in the data set that has a SAIDI/Day of zero.

c) Find the natural logarithm of each value in the data set.

d) Compute the average (α, or Alpha) and standard deviation (β or Beta) of the natural logarithms computed in step a).

e) Compute the threshold $T_{MED} = \exp(\alpha + 2.5 * \beta)$.

f) Any day in the next year with SAIDI > T_{MED} is a MED.

B.3 Random nature of distribution reliability

The reliability of electric power distribution systems is a *random process*, that is, a process that produces random values of a specific *random variable*. A simple example of a random process is rolling a die. The random variable is the value on the top face of the die after a roll, which can have integer values between one and six.

In electric power distribution system reliability, the random variables are the reliability indices defined in this guide. These are evaluated on a daily or yearly basis and take on values from zero to infinity.

B.4 Choice of SAIDI to identify Major Event Days

Four commonly used reliability indices are:

a) System Average Interruption Duration Index (SAIDI)

b) System Average Interruption Frequency Index (SAIFI)

c) Customer Average Interruption Duration Index (CAIDI)

d) Average Service Availability Index (ASAI)

These indices are actually measures of unreliability, as they increase when reliability becomes worse.

An ideal measure of unreliability would be customer cost of unreliability—the dollar cost of power outages to a utility's customers. This cost is a combination of the initial cost of an outage and accumulated costs during the outage. Unfortunately, the customer cost of unreliability has so far proven impossible to estimate accurately. In contrast, the reliability indices above are routinely and accurately computed from historical reliability data. The ability of an index to reflect customer cost of unreliability indicates the best one to use for MED identification.

Duration-related costs of outages are higher than initial costs, especially for major events, which typically have long duration outages. Thus, a duration-related index will be a better indicator of total costs than a frequency-related index like SAIFI or MAIFI. Because CAIDI is a value per customer, it does not reflect the size of outage events. Therefore, SAIDI best reflects the customer cost of unreliability, and is the index used to identify MEDs. SAIDI in minutes/day is the random variable used for MED identification.

The use of CMI per day was also considered. Like SAIDI, CMI is a good representation of customer cost of unreliability. In fact, SAIDI is just CMI divided by the number of customers in the utility. The number of customers can vary from year to year, especially in the case of mergers, and multiple years of data are used to find MEDs. Use of SAIDI accounts for the variation in customer count, while use of CMI does not. Therefore, SAIDI is preferred.

B.5 Probability distribution of distribution system reliability

B.5.1 Probability density functions and probability of exceeding a threshold value

MEDs will be days with larger SAIDI values. This suggests the use of a threshold value for daily SAIDI. The threshold value is called T_{MED}. Days with SAIDI greater than T_{MED} are MEDs. As the threshold increases, there will be fewer days with SAIDI values above the threshold. The relationship between the threshold and the number of days with SAIDI above the threshold is given by the *probability density function* of SAIDI/day.

The probability density function gives the probability that a specific value of a random variable will appear. For example, for a six-sided die, the probability that a one will appear in a given roll is one-sixth, and the value of the probability density function of one is one-sixth for this random process.

The probability that a value greater than one will occur is the sum of the probability densities for all values greater than one. Since each value has a probability density of one-sixth for the example, this sum is simply five-sixths. As the threshold increases, the probability decreases. For example, for a threshold of four, there are only two values greater than four, and the probability of rolling one of them is two-sixths, or one-third.

In the die rolling example, the random variable can have only discrete integer values. SAIDI/day is a continuous variable. In this case, the sum is replaced by an integral. The probability p that any given day will have a SAIDI/day value greater than a threshold value T is the integral of the probability density function from the threshold to infinity as shown in Eq. (B.1):

$$p(\mathrm{SAIDI} > T) = \int_T^{\infty} pdf(\mathrm{SAIDI})\, d\mathrm{SAIDI} \tag{B.1}$$

Graphically, the probability is the area under the probability density function above the threshold, as shown in Figure B.1.

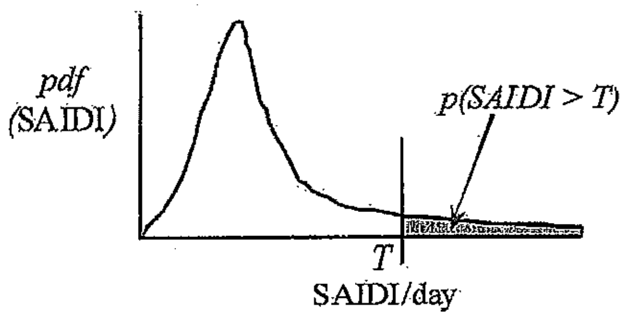


Figure B.1—The area under the probability density of function pdf (SAIDI)

If any given day has a probability p of being a MED, then the *expected value* [see Eq. (B.2)] of the number of MEDs in a year is the probability multiplied by the number of days in a year, as shown in Eq. (B.2):

$$E(MED/year) = 365 \cdot p(\text{SAIDI} > T_{MED}) \tag{B.2}$$

For example, if $p = 0.1$, then the expected number of MEDs in a year is 36.5. This does not mean that exactly 36.5 MEDs will occur. The actual number will vary due to the randomness of the process.

Using the die rolling example, the probability of getting a six in any roll is one-sixth. Therefore, the expected number of sixes in six rolls is one. However, if the die is rolled six times, there could be six sixes, or zero sixes, or any number in between. As the number of trials goes up, the number of sixes will approach one-sixth of the number of rolls, but for small numbers of rolls, there will be some variation from the expected value.

B.5.2 Gaussian, or normal, distribution

The expected number of MEDs per year can be computed for any given threshold if the shape of the probability density function is known. The shape of the probability density function is called the *probability distribution*. Specific types of shapes have specific names. The most well known is the *Gaussian distribution*, also called the *normal distribution*, or bell curve, shown in Figure B.2.

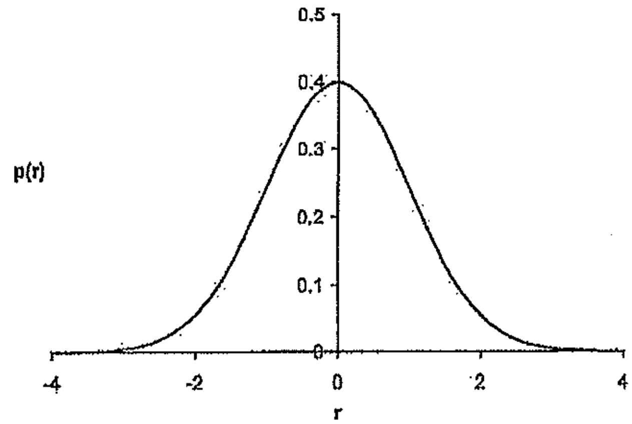


Figure B.2—Gaussian, or normal, probability distribution

The Gaussian distribution is completely described by its *mean*, or average value, (μ or Mu) and its *standard deviation* (σ or Sigma). The average value is at the center of the distribution (at 0 on the *x*-axis in Figure B.2), and the standard deviation is a measure of the spread of the distribution.

An important property of the Gaussian distribution is that the probability of exceeding a given threshold is a function of the number of standard deviations the threshold is from the mean. Eq. (B.3) expresses this concept in mathematical terms:

$$T_{MED} = \mu + n\sigma \tag{B.3}$$

The threshold is *n* standard deviations greater than the mean, and the probability of exceeding the threshold, $p(\text{SAIDI} > T_{MED})$, is a function only of *n*, and not of the mean and standard deviation. Values for this function are found in tables in the backs of probability textbooks and in, for example, standard spreadsheet functions. Table B.1 gives the probability of exceeding the threshold for different number of standard deviations *n*.

Table B.1—Probability of exceeding a threshold for the Gaussian distribution

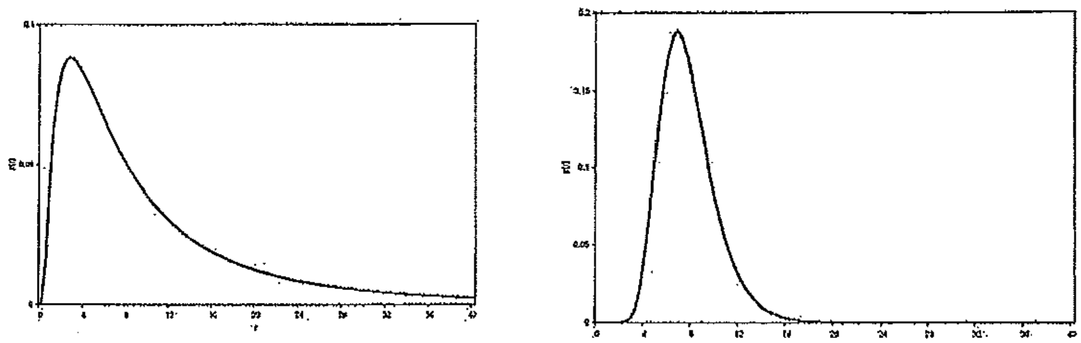
n	*p*
1	0.15866
2	0.02275
3	0.00135
6	9.9×10^{-10}

B.5.3 Three sigma

The term *three sigma* is often used loosely to designate a rare event. It comes from the Gaussian probability distribution. As Table B.1 shows, the probability of exceeding a threshold that is three standard deviations more than the mean is 0.00135, or about one and one-half tenths of one percent. If daily SAIDI had a Gaussian probability distribution, it would be relatively easy to agree on a three sigma definition for the MED threshold, T_{MED}. SAIDI does not have a Gaussian distribution. It has approximately a log-normal distribution.

B.6 Log-normal distribution

The random variable in the Gaussian distribution has a range from -∞ to ∞. In real life, many quantities, including distribution reliability, can only be zero or positive. This causes the probability distribution to skew, bunching up near the zero value and having a long tail to the right. The degree of skew depends on the ratio of mean to standard deviation. When the standard deviation is small compared to the mean, the log-normal distribution looks like the Gaussian distribution, as shown in Figure B.3(b). When it is large compared to the mean, it does not, as shown in Figure B.3(a). Daily reliability data usually has standard deviation values far larger than the mean.



(a) (b)

Figure B.3—Log-normal distributions: (a) Mean less than standard deviation (b) Mean greater than standard deviation

The usual way of determining if a set of data has a log-normal probability distribution is to take the natural logarithm of each value in the data set and examine the histogram. If the histogram looks like a Gaussian distribution, then the data has a log-normal distribution. Figure B.4 shows a histogram of the natural logs of daily SAIDI data for an anonymous utility. The histogram is approximately normally distributed, so the data is approximately log-normally distributed. Roughly a dozen utility data sets have been examined, and all are approximately log-normally distributed. No non-log-normally distributed utility data has so far been found. In addition, Monte Carlo simulation models of the distribution reliability process produce log-normally distributed data. Therefore, utility daily reliability is approximately log-normally distributed.

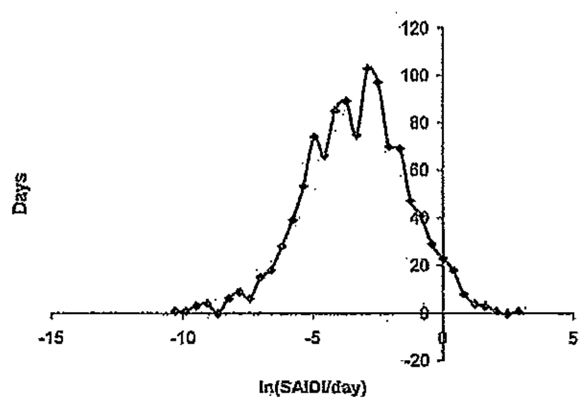


Figure B.4—Histogram of the natural logs of three years of daily SAIDI data from anonymous utility two supplied by the Distribution System Design Working Group

A consequence of the log-normality of daily reliability data is that the three sigma conditions no longer hold. In particular, the probability of exceeding a given threshold is no longer independent of the values of the average and standard deviation of the distribution. This means that using a method such as three sigma would result in significantly different numbers of MEDs for utilities with different average values of reliability, or with different standard deviation values. This seems inequitable.

Fortunately, the logarithms of log-normal data have a Gaussian distribution. If the average of the logarithms of the data is called α, or Alpha, and the standard deviation of the logarithms of the data is called β, or Beta, then α and β are the mean and standard deviation of a Gaussian distribution, and a threshold on the log of the data can be set that is independent of the values of α and β. Eq. (B.4) and Eq. (B.5) show these concepts mathematically.

$$\ln(T_{MED}) = \alpha + k\beta \tag{B.4}$$

$$T_{MED} = \exp(\alpha + k\beta) \tag{B.5}$$

The probability of exceeding T_{MED} is a function of k, just as it was a function of n in the Gaussian example. Table B.2 gives these probabilities as well as the expected number of MEDs for various values of k.

Table B.2—Probability of exceeding T_{MED} as a function of multiples of β

k	p	MEDs/yr
1	0.15866	57.9
2	0.02275	8.3
2.4	0.00822	3.0
2.5	0.00621	2.3
3	0.00135	0.5
6	9.9×10^{-10}	3.6E-07

B.6.1 Why 2.5?

Given an allowed number of MEDs per year, a value for k is easily computed. However, there is no analytical method of choosing an allowed number of MEDs/year. The chosen value of $k = 2.5$ is based on consensus reached among Distribution Reliability Working Group members on the appropriate number of days that should be classified as MEDs. As Table B.2 shows, the expected number of days for $k = 2.5$ is 2.3 MEDs/year. In practice, the experience of the committee members, representing a wide range of distribution utilities, was that more than 2.3 days were usually classified as MEDs, but that the days that were classified as MEDs were generally those that would have been chosen on qualitative grounds. The performance of different values of k were examined, and consensus was reached on $k = 2.5$.

B.7 Fairness of the 2.5β method

It is likely that reliability data from different utilities will be compared by utility management, public utilities commissions, and other interested parties. A fair MED classification method would classify, on average, the same number of MEDs per year for different utilities.

The two basic ways that utilities can differ in reliability terms are in the mean and standard deviation of their reliability data. Differences in means are attributable to differences in the environment between utilities, and differences in operating and maintenance practices. Differences in standard deviation are mostly attributable to size. Larger utilities have inherently smaller standard deviations.

As discussed above, using the mean and standard deviation of the logs of the data (α and β) to set the threshold makes the expected number of MEDs depend only on the multiplier and thus should classify the same number of MEDs for large and small utilities, and for utilities with low and high average reliability.

This is not the case for using the mean and standard deviation of the data without taking logarithms first. The expected number of MEDs varies with the mean and standard deviation. This variation occurs because of the log-normal nature of the reliability probability distribution.

Experience with the 2.5β method has shown that it is better than using mean and standard deviation, but it is not perfect. The number of MEDs identified per year is significantly higher than expected, and the average number of MEDs varies somewhat from utility to utility, with size affecting the value. These effects appear because the probability distribution of distribution system reliability is only approximately log-normal. Significant differences appear in the right hand tail of the distribution, which in general contains more probability than a perfect log-normal distribution. This "fat tail" effect accounts for the larger-than-predicted number of identified MEDs. The effect of utility size is less clearly understood.

Despite these issues, the 2.5β method of MED identification is much closer to the ideal fair process than using a Gaussian distribution, using the heuristic definitions that preceded it, or any other method proposed to date. It has been carefully tested and has been broadly accepted by the utilities in the Distribution Design Working Group and many other utilities and regulators that have adopted this guide.

B.8 Five years of data

From a statistical point of view, the more data used to calculate a threshold, the better. However, the random process producing the data changes over time as the distribution system is expanded and operating procedures are varied. Using too much historical data would suppress the effects of these changes.

The addition of another year of data should have a low probability of changing the MED classification of previous years. A result from order statistics gives the probability that the kth largest value in m samples will be exceeded f times in n future samples. It is given in Eq. (B.6):

$$p_{f|m,k,n} = \frac{k}{n+k-f} \frac{\binom{m}{k}\binom{n}{f}}{\binom{n+m}{n+k-f}} \tag{B.6}$$

For example, if $M = 3$ years of data, then $m = 1\,095$ samples. If $f = 3$ MEDs/year, then the largest non-MED is the $k = 1\,095 - 9 = 1\,086^{th}$ ordered sample. The probability of $f = 3$ days in the next year of $n = 365$ samples exceeding the size of the largest non-MED is found from the equation to be 0.194 (19.4%). In Figure B.5, p is plotted against M for several values of f.

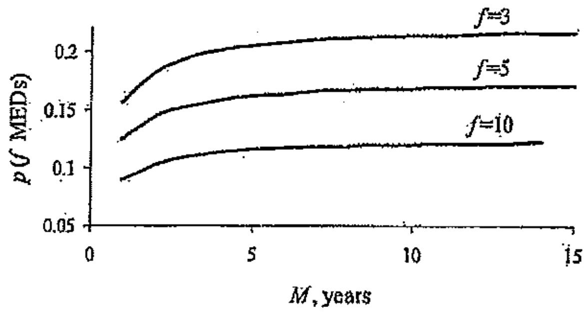


Figure B.5—Probability of exactly *f* new MEDs in the next year of data using *M* years of historical data

The consensus of the Design Working Group members was that five years was the appropriate amount of data to collect. The group felt that the distribution system would change enough to invalidate any extra accuracy from more than five years of data.

Annex C

(informative)

Internal data subset

C.1 Calculation of reliability indices for subsets of data for internal company use

Reliability performance can be assessed for different purposes. It may be advantageous to calculate reliability indices without planned interruptions in order to review performance during unplanned events. In another case, it may be advantageous to review only sustained interruptions. Assessment of performance trends and goal setting should be based on normal event days (neglecting the impact of MEDs). Utilities and regulators determine the most appropriate data to use for reliability performance monitoring. When indices are calculated using partial data sets, the basis should be clearly defined for the users of the indices. At a minimum, reliability indices based on all collected data for a reporting period and analyzed as to normal versus MED classifications should be provided. Indices based on subsets of collected data may be provided as specific needs dictate.

2016

OMS Reliability Reports YTD

Month	Target SAIDI	PY Raw SAIDI	CY Raw SAIDI	PY MED SAIDI	CY MED SAIDI
JAN	8.4	5.03	5.31	5.03	5.31
FEB	12.5	17.74	9.1	9.12	9.1
MAR	18.8	21.55	20.86	12.94	14.49
APR	25	26.65	36.17	18.05	25.34
MAY	43.8	37.55	45.32	28.96	34.51
JUN	62.5	78.09	53.51	38.49	42.7
JUL	81.3	100.63	67.02	61.06	56.22
AUG	100	112.45	75.39	68.56	64.61
SEP	106.3	152.34	318.84	76.5	70.48
OCT	112.5	1383.38	323.62	81.6	75.45
NOV	119.2	1386.96	326.72	86.2	78.73
DEC	125	1390.22	329.61	90.52	81.82

2016

OMS Reliability Reports YTD

Month	Target SAIFI	PY Raw SAIFI	CY Raw SAIFI	PY MED SAIFI	CY MED SAIFI
JAN	0.15	0.07	0.07	0.07	0.07
FEB	0.21	0.21	0.14	0.11	0.14
MAR	0.31	0.26	0.26	0.17	0.23
APR	0.41	0.35	0.41	0.26	0.34
MAY	0.68	0.51	0.52	0.41	0.45
JUN	0.95	0.8	0.64	0.53	0.57
JUL	1.22	1.1	0.84	0.84	0.77
AUG	1.48	1.27	0.95	0.98	0.88
SEP	1.58	1.61	1.65	1.09	0.94
OCT	1.68	2.62	1.73	1.14	1.02
NOV	1.79	2.69	1.8	1.2	1.09
DEC	1.9	2.75	1.85	1.27	1.14

2017

OMS Reliability Reports YTD

Month	Target SAIDI	PY Raw SAIDI	CY Raw SAIDI	PY MED SAIDI	CY MED SAIDI
JAN	8.4	5.03	5.31	5.03	5.31
FEB	12.5	17.74	9.1	9.12	9.1
MAR	18.8	21.55	20.86	12.94	14.49
APR	25	26.65	36.17	18.05	25.34
MAY	43.8	37.55	45.32	28.96	34.51
JUN	62.5	78.09	53.51	38.49	42.7
JUL	81.3	100.63	67.02	61.06	56.22
AUG	100	112.45	75.39	68.56	64.61
SEP	106.3	152.34	318.84	76.5	70.48
OCT	112.5	1383.38	323.62	81.6	75.45
NOV	119.2	1386.96	326.72	86.2	78.73
DEC	125	1390.22	329.61	90.52	81.82

2017 **OMS Reliability Reports YTD**

Month	Target SAIFI	PY Raw SAIFI	CY Raw SAIFI	PY MED SAIFI	CY MED SAIFI
JAN	0.15	0.07	0.07	0.07	0.07
FEB	0.21	0.21	0.14	0.11	0.14
MAR	0.31	0.26	0.26	0.17	0.23
APR	0.41	0.35	0.41	0.26	0.34
MAY	0.68	0.51	0.52	0.41	0.45
JUN	0.95	0.8	0.64	0.53	0.57
JUL	1.22	1.1	0.84	0.84	0.77
AUG	1.48	1.27	0.95	0.98	0.88
SEP	1.58	1.61	1.65	1.09	0.94
OCT	1.68	2.62	1.73	1.14	1.02
NOV	1.79	2.69	1.8	1.2	1.09
DEC	1.9	2.75	1.85	1.27	1.14

2015 Response 7-21d

OMS Reliability Reports YTD

Month	Target SAIDI	PY Raw SAIDI	CY RAW SAIDI	PY MED SAIDI	CY MED SAIDI
JAN	9.3	24.9	4	10.2	4
FEB	13.9	820.9	11.6	15.5	11.6
MAR	20.9	828.4	15.8	23.4	15.8
APR	27.8	833.4	24.3	28.6	24.3
MAY	48.7	843.6	30.8	39.1	30.8
JUN	69.5	856.1	47.5	52	47.5
JUL	90.4	869.8	71.7	66.1	64.2
AUG	111.2	882.1	86.3	74.4	74.3
SEP	118.2	889.4	95.5	82.2	83.5
OCT	125.1	895	146.6	88.2	88.6
NOV	132.5	904.9	150.9	93.1	92.9
DEC	139	907.9	154.5	96.6	96.6

OMS Reliability Reports YTD

Month	Target SAIFI	PY Raw SAIFI	CY Raw SAIFI	PY MED SAIFI	CY MED SAIFI
JAN	.15	.33	.06	.15	.06
FEB	.21	1.13	.18	.21	.18
MAR	.31	1.27	.23	.35	.23
APR	.41	1.37	.35	.45	.35
MAY	.68	1.53	.44	.61	.44
JUN	.95	1.73	.64	.81	.64
JUL	1.22	1.92	.9	1	.86
AUG	1.48	2.07	1.11	1.11	1.01
SEP	1.58	2.19	1.23	1.23	1.13
OCT	1.68	2.29	1.5	1.32	1.21
NOV	1.79	2.41	1.56	1.41	1.27
DEC	1.9	2.45	1.62	1.44	1.34

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-22:

Provide a calculation of the income tax expense included in SCE&G's present base rates, excluding the income tax expense related to the return on the BLRA CWIP that was provided previously in response to ORS 4-76. Provide all calculations and workpapers, including electronic spreadsheets in live format and with all formula intact.

RESPONSE 7-22:

Please see attached.

RESPONSIBLE PERSON: Tammy Harrison

South Carolina Electric and Gas Company
Electric Cost of Service Study
12 Months Ending 12/31/11

	Description	ALLOCATOR	RETAIL
1	DEVELOPMENT OF STATE INCOME TAX		522,888
2	OPERATING INCOME BEFORE TAXES		
3	ALLOWABLE DEDUCTIONS		
4	Capitalized and Use Tax	POO	(19,018)
5	Interest	RB	138,285
6	Depreciation (Over Book)	DEPREJ	202,572
7	Nuclear Fuel Expense	E10	(93,834)
8	Removal Cost and Property Tax	P10	1,456
9	Employee Benefits	LABOR	(3,147)
10	Non-Taxable State Revenue	POO	2,821
11	Unbilled Revenue	ENE1	26,062
12	TOTAL ALLOWABLE DEDUCTIONS		255,198
13	STATE TAXABLE INCOME		267,690
14	STATE INCOME TAX @ 5%		13,384
15	STATE INVESTMENT TAX CREDIT		
16	PRODUCTION	P10	(2,770)
17	TRANSMISSION AND DISTRIBUTION	TD	(2,068)
18	GENERAL AND COMMON	GC	(266)
19	STATE INVESTMENT TAX CREDIT		(5,104)
20	TOTAL ACCRUED FOR CURRENT YEAR		8,280
21	ADJUSTMENTS TO TAX		
22	State Tax Prior Year Adjustments	POO	1,452
23	**TOTAL STATE INCOME TAX**		9,732

South Carolina Electric and Gas Company
Electric Cost of Service Study
12 Months Ending 12/31/11

	Description	ALLOCATOR	RETAIL
1	DEVELOPMENT OF FEDERAL INCOME TAX		522,888
2	OPERATING INCOME BEFORE TAXES		
3	ALLOWABLE DEDUCTIONS		
4	Capitalized and Use Tax	POO	(9,451)
5	Interest	RB	138,285
6	Depreciation (Over Book)	DEPREJ	339,197
7	Nuclear Fuel Expense	E10	(93,834)
8	Removal Cost and Property Tax	P10	1,456
9	Employee Benefits	LABOR	(3,147)
10	Unbilled Revenue	ENE1	26,062
11	State Income Tax		8,280
12	TOTAL ALLOWABLE DEDUCTIONS		406,850
13	FEDERAL TAXABLE INCOME		116,038
14	FEDERAL INCOME TAX @ 35%		40,613
15	State Tax Prior Year Adjustments	POO	10,922
16	**TOTAL FEDERAL INCOME TAX**		51,536

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-23:

Provide the monthly AFUDC rate used for the NND project costs not included in revised rates from the date construction commenced through December 2017. Provide the calculation of the monthly rate used for this purpose, including capital structure and component costs.

RESPONSE 7-23:

See Attachment. The provided responses reflect the calculation of the final effective AFUDC rate for the years 2008-2017. AFUDC is calculated monthly at an estimated rate and trued up annually to a final effective rate for the year.

RESPONSIBLE PERSON: William Hutson

SOUTH CAROLINA ELECTRIC & GAS COMPANY

AFUDC2007
01/04/16

COMPUTATION OF AFUDC RATES
BY ORDER NE. 561 METHOD
2008
DECEMBER 2008 FINAL RATE ELECTRIC

	AMOUNT (1)	CAPITALIZATION RATIO (2)	COST RATES (3)	S/W (4)	WEIGHTED COST RATES FOR GROSS AFUDC RATES (5)
Weighted Average Short-Term Debt Balance	209,089,795	s	3.320 x	51.90% =	1.72% x
				1-S/W	
Long-Term Debt Beg. of Year	1,821,488,400	39.96% x	6.090 x	48.10% =	1.17% x
Preferred Stock Beg. of Year	114,158,800	2.50% x	6.420 x	48.10% =	0.08%
Common Equity Beg. of Year	2,622,443,489	57.53% x	11.00 x	48.10% =	3.04%
Total Capitilization	4,558,090,689	100.00%			
AFUDC Rate					6.02%
Average of 13 monthly balances- Account 107 Account 120.1	402,893,386				
W-Total					

AFUDC ACTUALLY CAPITALIZED
AFUDC AMOUNT BY ORDER 561
DIFFERENCE

		MO. PERCENT
DEBT - 432.0000	48.10%	0.0024114
EQUITY - 419.1000	51.90%	0.0026014
	100.00%	0.0050127
		0.0601529

SOUTH CAROLINA ELECTRIC & GAS COMPANY

AFUDC 2009
08/30/17

COMPUTATION OF AFUDC RATES
BY ORDER NE. 561 METHOD
2009
ELECTRIC-Final

	AMOUNT (1)	CAPITALIZATION RATIO (2)	COST RATES (3)	S/W (4)	WEIGHTED COST RATES FOR GROSS AFUDC RATES (5)
Weighted Average Short-Term Debt Balance	34,369,925	s	0.008 x	5.27% =	0.00% x
				1-S/W	
Long-Term Debt Beg. of Year	2,696,488,400	48.90% x	5.920 x	94.73% =	2.74% x
Preferred Stock Beg. of Year	113,758,800	2.06% x	6.430 x	94.73% =	0.13%
Common Equity Beg. of Year	2,703,692,957	49.03% x	11.00 x	94.73% =	5.11%
Total Capitilization	5,513,940,157	100.00%			
AFUDC Rate					**7.98%**

Average of 13 monthly balances- Account 107 Account 120.1	652,523,287	AFUDC ACTUALLY CAPITALIZED AFUDC AMOUNT BY ORDER 561 DIFFERENCE		
W-Total				MO. PERCENT
		DEBT - 432.0000	34.38%	0.0022858
		EQUITY - 419.1000	65.62%	0.0043627
			100.00%	0.0066486
				0.0797829

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF AFUDC RATES
BY ORDER NE. 561 METHOD
2010
New Nuclear

	AMOUNT (1)	CAPITALIZATION RATIO (2)	COST RATES (3)	S/W (4)	WEIGHTED COST RATES FOR GROSS AFUDC RATES (5)
Weighted Average Short-Term Debt Balance	99,558,000	s	0.410 x	15.91% =	0.07% x
				1-S/W	
Long-Term Debt Beg. of Year	2,815,425,000	47.10% x	5.990 x	84.09% =	2.37% x
Preferred Stock Beg. of Year		0.00% x	0.000 x	84.09% =	0.00%
Common Equity Beg. of Year	3,162,442,174	52.90% x	11.00 x	84.09% =	4.89%
Total Capitilization	5,977,867,174	100.00%			
AFUDC Rate					**7.33%**
Average of 13 monthly balances- Account 107 Account 120.1	625,733,785				
W-Total					

AFUDC ACTUALLY CAPITALIZED
AFUDC AMOUNT BY ORDER 561
DIFFERENCE

		MO. PERCENT
DEBT - 432.0000	33.25%	0.0020313
EQUITY - 419.1000	66.75%	0.0040778
	100.00%	0.0061091
		0.0733091

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF AFUDC RATES
BY ORDER NE. 561 METHOD
2011
New Nuclear

	AMOUNT (1)	CAPITALIZATION RATIO (2)	COST RATES (3)	S/W (4)	WEIGHTED COST RATES FOR GROSS AFUDC RATES (5)
Weighted Average Short-Term Debt Balance	273,557,480	s	0.400 x	50.36% =	0.20% x
				1-S/W	
Long-Term Debt Beg. of Year	2,715,425,000	44.14% x	6.330 x	49.64% =	1.39% x
Preferred Stock Beg. of Year	100,000	0.00% x	0.000 x	49.64% =	0.00%
Common Equity Beg. of Year	3,436,711,083	55.86% x	11.00 x	49.64% =	3.05%
Total Capitilization	6,152,236,083	100.00%			
AFUDC Rate					**4.64%**
Average of 13 monthly balances-	543,208,363				

AFUDC ACTUALLY CAPITALIZED
AFUDC AMOUNT BY ORDER 561
DIFFERENCE

W-Total

		MO. PERCENT
DEBT - 432.0000	34.24%	0.0013236
EQUITY - 419.1000	65.76%	0.0025419
	100.00%	0.0038655
		0.0463860

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF AFUDC RATES
BY ORDER NE. 561 METHOD
2012
New Nuclear

	AMOUNT (1)	CAPITALIZATION RATIO (2)	COST RATES (3)	S/W (4)	WEIGHTED COST RATES FOR GROSS AFUDC RATES (5)
Weighted Average Short-Term Debt Balance	176,895,858	s	0.490 x	28.71% =	0.14% x
				1-S/W	
Long-Term Debt Beg. of Year	2,915,425,000	44.31% x	6.120 x	71.29% =	1.93% x
Preferred Stock Beg. of Year	100,000	0.00% x	0.000 x	71.29% =	0.00%
Common Equity Beg. of Year	3,664,493,375	55.69% x	11.00 x	71.29% =	4.37%
Total Capitilization	6,580,018,375	100.00%			
AFUDC Rate					**6.44%**
Average of 13 monthly balances- Account 107 Account 120.1	616,251,230				
W-Total					

AFUDC ACTUALLY CAPITALIZED
AFUDC AMOUNT BY ORDER 561
DIFFERENCE

		MO. PERCENT
DEBT - 432.0000	32.20%	0.0017282
EQUITY - 419.1000	67.80%	0.0036396
	100.00%	0.0053679
		0.0644144

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF AFUDC RATES
BY ORDER NE. 561 METHOD
2013
New Nuclear

	AMOUNT (1)	CAPITALIZATION RATIO (2)	COST RATES (3)	S/W (4)	WEIGHTED COST RATES FOR GROSS AFUDC RATES (5)
Weighted Average Short-Term Debt Balance	116,483,397	s	0.340 x	16.83% =	0.06% x
				1-S/W	
Long-Term Debt Beg. of Year	3,381,465,000	46.25% x	5.930 x	83.17% =	2.28% x
Preferred Stock Beg. of Year	100,000	0.00% x	0.000 x	83.17% =	0.00%
Common Equity Beg. of Year	3,929,228,084	53.75% x	11.00 x	83.17% =	4.92%
Total Capitilization	7,310,793,084	100.00%			
AFUDC Rate					**7.26%**

Average of 13 monthly balances-
Account 107: 692,308,595
Account 120.1

W-Total

AFUDC ACTUALLY CAPITALIZED
AFUDC AMOUNT BY ORDER 561
DIFFERENCE

		MO. PERCENT
DEBT - 432.0000	32.23%	0.0019488
EQUITY - 419.1000	67.77%	0.0040977
	100.00%	0.0060465
		0.0725582

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF AFUDC RATES
BY ORDER NE. 561 METHOD
2014
New Nuclear

	AMOUNT (1)	CAPITALIZATION RATIO (2)	COST RATES (3)	S/W (4)	WEIGHTED COST RATES FOR GROSS AFUDC RATES (5)	
Weighted Average Short-Term Debt Balance	155,285,971	s	0.300 x	21.07% =	0.06% x	
				1-S/W		
Long-Term Debt Beg. of Year	3,628,770,000	45.35% x	5.720 x	78.93% =	2.05% x	
Preferred Stock Beg. of Year	100,000	0.00% x	0.000 x	78.93% =	0.00%	2.11%
Common Equity Beg. of Year	4,372,702,479	54.65% x	11.00 x	78.93% =	4.74%	4.74%
Total Capitilization	8,001,572,479	100.00%				
AFUDC Rate					**6.86%**	6.86%
Average of 13 monthly balances- Account 107 Account 120.1	737,122,504					

AFUDC ACTUALLY CAPITALIZED
AFUDC AMOUNT BY ORDER 561
DIFFERENCE

W-Total

			MO. PERCENT
DEBT	- 432.0000	30.79%	0.0017590
EQUITY	- 419.1000	69.21%	0.0039541
		100.00%	0.0057131
			0.0685570

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF AFUDC RATES
BY ORDER NE. 561 METHOD
2015
New Nuclear

	AMOUNT (1)	CAPITALIZATION RATIO (2)	COST RATES (3)	S/W (4)	WEIGHTED COST RATES FOR GROSS AFUDC RATES (5)	
Weighted Average Short-Term Debt Balance	262,270,277	s	0.437 x	32.55% =	0.14% x	
				1-S/W		
Long-Term Debt Beg. of Year	3,928,770,000	45.88% x	5.670 x	67.45% =	1.75% x	
Preferred Stock Beg. of Year	100,000	0.00% x	0.000 x	67.45% =	0.00%	1.90%
Common Equity Beg. of Year	4,633,786,219	54.12% x	11.00 x	67.45% =	4.02%	4.02%
Total Capitalization	8,562,656,219	100.00%				
AFUDC Rate					**5.91%**	5.91%
Average of 13 monthly balances- Account 107 Account 120.1	805,776,088		AFUDC ACTUALLY CAPITALIZED AFUDC AMOUNT BY ORDER 561			
W-Total						MO. PERCENT
			DEBT - 432.0000		32.09%	0.0015809
			EQUITY - 419.1000		67.91%	0.0033460
					100.00%	0.0049269
						0.0591230

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF AFUDC RATES
BY ORDER NE. 561 METHOD
2016
New Nuclear

	AMOUNT (1)	CAPITALIZATION RATIO (2)	COST RATES (3)	S/W (4)	WEIGHTED COST RATES FOR GROSS AFUDC RATES (5)	
Weighted Average Short-Term Debt Balance	490,521,212	s	0.838 x	47.24% =	0.40% x	
				1-S/W		
Long-Term Debt Beg. of Year	4,428,770,000	46.86% x	5.840 x	52.76% =	1.44% x	
Preferred Stock Beg. of Year	100,000	0.00% x	0.000 x	52.76% =	0.00%	1.84%
Common Equity Beg. of Year	5,022,937,909	53.14% x	10.96 x	52.76% =	3.07%	3.07%
Total Capitalization	9,451,807,909	100.00%				
AFUDC Rate					**4.91%**	4.91%
Average of 13 monthly balances- Account 107 Account 120.1	1,038,445,847					

W-Total

AFUDC ACTUALLY CAPITALIZED
AFUDC AMOUNT BY ORDER 561

			MO. PERCENT
DEBT	- 432.0000	37.45%	0.0015332
EQUITY	- 419.1000	62.55%	0.0025610
		100.00%	0.0040942
			0.0491306

Rate	# of Months	Weighting	
11.00%	11	91.67%	10.08%
10.50%	1	8.33%	0.88%
	12		10.96%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF AFUDC RATES
BY ORDER NE. 561 METHOD
2017
New Nuclear - Generation

	AMOUNT (1)	CAPITALIZATION RATIO (2)	COST RATES (3)	S/W (4)	WEIGHTED COST RATES FOR GROSS AFUDC RATES (5)	
Weighted Average Short-Term Debt Balance	521,748,827	s	1.320 x	62.40% =	0.82% x	
				1-S/W		
Long-Term Debt Beg. of Year	4,928,770,000	47.99% x	5.850 x	37.60% =	1.06% x	
Preferred Stock Beg. of Year	100,000	0.00% x	0.000 x	37.60% =	0.00%	1.88%
Common Equity Beg. of Year	5,341,449,396	52.01% x	10.50 x	37.60% =	2.05%	2.05%
Total Capitalization	10,270,319,396	100.00%				
AFUDC Rate					**3.93%**	3.93%
Average of 13 monthly balances- Account 107 Account 120.1	836,151,092		AFUDC ACTUALLY CAPITALIZED AFUDC AMOUNT BY ORDER 561			
W-Total						MO. PERCENT
			DEBT - 432.0000		47.79%	0.0015661
			EQUITY - 419.1000		52.21%	0.0017111
					100.00%	0.0032772
						0.0393266

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-24:

Describe the South Carolina Department of Revenue's claim against SCE&G for sales tax on the NND construction costs. Describe the current status. Provide a copy and the amount of the assessment, including all schedules that were developed by the SCDOR in support of the assessment.

RESPONSE 7-24:

On January 26, 2018, the South Carolina Department of Revenue ("SCDOR") notified SCE&G that it was initiating an audit of the Company's sales and use tax returns for the periods September 1, 2008 through December 31, 2017. On February 8, 2018, at an introductory meeting regarding the audit, the SCDOR informed the Company that it believes that the exemption for sales and use tax for purchases related to the Nuclear Project no longer applies because Unit 2 and Unit 3 will not be placed into service and no electricity will be manufactured for sale.

On June 1, 2018, SCE&G received a notice of proposed assessment and related information. A copy of the proposed assessment, including the documents accompanying the proposed assessment are attached. SCDOR has not provided any schedules or other information supporting its proposed assessment. Accordingly, SCE&G is not in possession of information responsive to this portion of ORS's request.

SCE&G has ninety days from the date of the proposed assessment to appeal the proposed assessment by sending a written protest. The Company intends to appeal the proposed assessment and vigorously contest the SCDOR's position.

RESPONSIBLE PERSON: Virginia Smith

1350

STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE

Explanation of Audit Assessments and Adjustments

AS-21
(Rev. 08/24/16)
6391

File Number: 020800475
Letter ID: L0006859830
Date Issued: May 31, 2018

SCE&G COMPANY, PRINCIPAL SUBSIDIARY OF SCANA CORPORATION
VC SUMMER NUCLEAR PLANT
CORPORATE TAX DEPARTMENT (050)
COLUMBIA SC 29218-0001

On August 27, 2008, a Special 19 (Direct Pay) Agreement was entered into by South Carolina Electric & Gas Company and the South Carolina Department of Revenue whereby purchases could be made Sales and Use Tax free using the exemption certificate. This agreement allowed SCE&G to extend the exemption certificate to contractors and sub-contractors to purchase material and equipment that would be tax exempt under S.C. Code Section 12-36-2120 (17) and other sections that relate to constructing a manufacturing facility, in particular the construction of the AP1000 Nuclear Units (units 2 & 3) to be located in Fairfield County, SC. The Exemption Certificate (ST-9) was issued with an effective date of September 4, 2008.

The Department received an email from Keith R. Whitman on July 31, 2017 announcing that SCANA was abandoning construction of the two new nuclear units at the V.C. Summer Nuclear Plant project in Jenkinsville, SC.

The Department sent a letter to SCANA on October 17, 2017 stating it was withdrawing the Special 19 Exemption Certificate and requested that all copies of the exemption certificate be returned. Copies of the exemption certificates were return on October 25, 2017.

On January 26, 2018, the Department mailed an Initial Audit Appointment letter to SCANA Corporation to the attention of Virginia Smith. The letter scheduled the initial audit meeting for February 8, 2018.

On February 8, 2018, an initial audit meeting was held with SCANA personnel and representatives as well as Department Auditors to further clarify what documents the Department was requesting to begin the audit.

On February 20, 2018 an audit letter was sent by the Department to SCANA with a list of requested documents for our examination which included but was not limited to copies of pay applications/contracts for all work performed onsite, copies of all invoice backup related to pay applications/contracts, and records related to the construction cost information filed with the Public Service Commission. A request was received from SCANA to extend the time to provide the documents, and the extension was granted until April 6, 2018.

On April 6, 2018, a letter was received from the Richardson Plowden Law Firm and a flash drive with some of the requested documents for review. Since all of the requested information was not provided, a Proposed Notice of Assessment was generated. Total cost of the project was determined to be $10.4 billion based on information obtained by the Department. 40% of the project cost was allocated to labor cost and 60% of the project cost was allocated to capital cost. A total tax measure of $6,240,000,000.00 was used to calculate use tax due on construction material costs. Credit was given for use tax paid throughout the life of the project.

LOGAN MITCHELL, Field Audit
Email: Logan.Mitchell@dor.sc.gov, Phone: +1 (803) 898-5908, Fax: +1 (803) 896-0020
300A Outlet Pointe Blvd, Columbia, South Carolina 29210

1350

STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE
Proposed Assessment

AS-6
(Rev. 04/12/18)
6376

File Number: 020800475
Letter ID: L0006763530
Date Issued: May 31, 2018

SCE&G COMPANY, PRINCIPAL SUBSIDIARY OF SCANA CORPORATION
VC SUMMER NUCLEAR PLANT
CORPORATE TAX DEPARTMENT (050)
COLUMBIA SC 29218-0001

Taxpayer:
An audit of your South Carolina Sales and Use Tax return(s) from 9/01/2008 thru 12/31/2017 has been conducted. Enclosed you will find an explanation of our **Proposed Assessment.** Below is a summary of our findings if paid by 06/28/2018:

Tax:	$410,092,995.09
Penalty:	$0.00
Interest:	$10,916,874.26
Prepayments:	($0.00)
Total:	$421,009,869.35

Failure to respond to this notice by 08/27/2018 will result in the accrual of additional penalties and/or interest, and further collection action will be taken. Please refer to the reverse side for instructions on how to proceed. Should you have any questions, please do not hesitate to contact this office.

LOGAN MITCHELL, Field Audit
Email: Logan.Mitchell@dor.sc.gov, Phone: +1 (803) 898-5908, Fax: +1 (803) 896-0020
300A Outlet Pointe Blvd, Columbia, South Carolina 29210

This demand for payment is not applicable if you are currently in bankruptcy proceedings under Title 11 of the U.S. Code. Any monies due will be sought in accordance with the provisions of Title 11.

----------------------------------cut along dotted line----------------------------------

1350

SC DEPARTMENT OF REVENUE
Audit Payment

C-370
(Rev. 01/18/18)
6370

Pay online for free at MyDORWAY.dor.sc.gov.

Vouchers and payments may also be mailed to:

South Carolina Department of Revenue
P.O. Box 2535
Columbia, SC 29202-2535

SOUTH CAROLINA ELECTRIC & GAS COMPANY

Media	241364796
File Number	020800475
Amount Due	$421,009,869.35
Balance Remitted	

63701023 01 000241364796 00 00 00000000 42100986935 9

If you agree with the changes detailed on this notice and any enclosed explanations, the balance should be remitted to this office within 30 days from the issue date of this letter to avoid additional penalties and interest, if applicable. To pay by check, please mail your payment **and the voucher** from the front page as addressed on the voucher to ensure proper processing.

If you agree with the Department's determination, but are unable to make full payment at this time, please complete the enclosed Waiver of Restriction on Assessment (SC870) and return it to this office as soon as possible. Upon receipt of this document, a final assessment will be issued.

You may agree with portions of the proposed assessment and disagree with others. The portion of the assessment with which you agree may be paid to avoid additional interest and penalty, and the remainder can be appealed.

If you disagree with part or all of the proposed assessment, you may make an appeal by sending a written protest within **90 days** from the date of this proposed assessment.

Protest forms (C-245) are available online at www.dor.sc.gov, by calling (803) 898-5320 or you may visit any South Carolina Department of Revenue office. You may choose to send a letter rather than using the Form C-245. The letter must contain the following information:

1. Taxpayer's name (individual, corporation, etc.)
2. Taxpayer's Identification number (Social Security, Federal Employer Identification, License, etc.)
3. Period for which the tax is proposed
4. Type of tax in dispute (individual income, sales, etc.)
5. All of the reasons you disagree with the proposed assessment

If you have any questions, please call the telephone number shown on the front of this proposed assessment.

TAXPAYER'S BILL OF RIGHTS

- You have the right to apply for assistance from the Taxpayer Rights' Advocate within the Department of Revenue. The advocate or his designee is responsible for facilitating resolution of taxpayer complaints and problems.
- You have the right to request and receive forms, instructions and other written materials in plain, easy-to-understand language.
- You have the right to prompt, courteous service from us in all your dealings with the Department of Revenue.
- You have the right to request and receive written information guides, which explain in simple and nontechnical language, appeal procedures and your remedies as a taxpayer.
- You have the right to receive notices which contain descriptions of the basis for and identification of amounts of any tax, interest and penalties due.

1350

STATE OF SOUTH CAROLINA
DEPARTMENT OF REVENUE
Waiver of Restrictions on Assessment/Collection

SC-870
(Rev. 12/06/04)
3309

File Number: 020800475
Letter ID: L0006766578
Date Issued: May 31, 2018

SCE&G COMPANY, PRINCIPAL SUBSIDIARY OF SCANA CORPORATION
VC SUMMER NUCLEAR PLANT
CORPORATE TAX DEPARTMENT (050)
COLUMBIA SC 29218-0001

Increase (Decrease) in Tax, Interest and Penalties:
Type of Tax: Sales and Use Tax
Periods Covered: 9/01/2008 thru 12/31/2017
Tax: $410,092,995.09
Penalty: $0.00
Interest $10,916,874.26
Total: $421,009,869.35
This information was prepared by Logan Mitchell. Telephone Number: 1+(803)898-5908

PLEASE READ THE INSTRUCTIONS ON THE REVERSE SIDE

Consent to Assessment and Collection of Additional Tax or Acceptance of Overassessment:

I have read and understand the instructions on the reverse side. I consent to the assessment and collection of any additional tax and penalties or accept any decrease in tax and penalties shown above, plus any interest provided by law. I understand that by signing this waiver, I consent to the above determination amount(s) and must pay the additional amounts prior to contesting this matter any further.

Taxpayer's Signature: ______________________________ Date: ________________

Spouse's Signature: ______________________________ Date: ________________

Corporation Name (if applicable): ______________________________________

Signature: ________________ Title: ________________ Date: ________________

GENERAL INFORMATION AND INSTRUCTIONS
SC870 (Rev. 12/6/04)

IMPORTANT: By signing this form, the taxpayer (1) agrees to pay the tax, interest, and penalties stated to be due; and (2) gives up the right to appeal this matter further. Interest and applicable penalties will continue to accrue until the balance due the Department is paid in full. Signing this form does **not** affect your right to file a claim for refund and does not prevent the Department from assessing additional tax found to be due at a later date.
NOTE: If you wish to give up your right to file a claim for refund and prevent the Department from assessing additional amounts at a later date, a SC870AD should be executed in lieu of this SC870.

CLAIM FOR

Executing this document does not prevent you from seeking a refund of State taxes paid. The refund claim must be filed within three years from the date the return was filed, or two years from the date of payment of the tax, whichever is later. See the SC Information Guide about the claim for refund procedure for additional information.

EXECUTING THIS

If this waiver relates to a joint individual income tax return, both husband and wife must sign the waiver.

If the SC870 is executed on behalf of a corporation, the waiver must include the corporation's name as well as the signature and title of the corporate officer executing this document.

If this waiver is associated with an income tax examination of a partnership or "S" corporation, each partner or shareholder must execute a separate form.

If this waiver is signed by someone acting in a fiduciary capacity (e.g. a personal administrator or trustee), Internal Revenue Service Form 56, Notice Concerning Fiduciary Relationship, must accompany this form unless previously provided.

An attorney, CPA or other agent may execute this form on behalf of a client provided such authority is granted in a power of attorney. The power of attorney must accompany this form unless previously provided.

GENERAL

We have an agreement with the Internal Revenue Service which provides for the exchange of tax information. If this change affects returns filed with the Internal Revenue Service, amended federal return(s) may need to be filed.

If you have any questions about this waiver, please contact the preparer.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-25:

Indicate whether SCE&G will seek to recover the sales tax on the NND construction costs from retail customers. If so, describe the manner and form this proposal will take, e.g., an addition to the NND costs recoverable through the CCR under the Merger CBP. If not, confirm that SCE&G will charge this cost to income below the line.

RESPONSE 7-25:

As stated in Response 7-24, SCE&G intends to appeal the proposed assessment issued by the South Carolina Department of Revenue ("SCDOR") by sending a written protest and vigorously contesting the SCDOR's position. It is unknown at this time whether SCE&G will be required to pay the assessment. Therefore, and without waiving but specifically reserving its rights to recover such expense if it is incurred, SCE&G is unable to indicate at this time whether it will seek to recover any such sales tax on the NND construction costs from retail customers.

RESPONSIBLE PERSON: Virginia Smith

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OFFICE OF REGULATORY STAFF'S CONTINUING
AUDIT INFORMATION REQUEST
DOCKET NO. 2017-207-E (8th Continuing AIR)
DOCKET NO. 2017-305-E (7th Continuing AIR)
DOCKET NO. 2017-370-E (7th Continuing AIR)

REQUEST 7-26:

Confirm that SCE&G will not seek to use an imputed capital structure to "restore" the effects of impairment losses charged to income below the line related to the BLRA costs (NND costs and related regulatory assets) for any ratemaking purposes, other than the proposed use of a "fixed" cost of capital for the CCR under the Merger CBP. If this is not correct, then provide a correct statement and describe each such effect on the ratemaking process and the costs recovered from customers.

RESPONSE 7-26:

The statements contained in Question 7-26 cannot be confirmed.

The full amount of SCE&G's investment in the NND Project represents investment in utility assets that was lawfully and prudently made and was thoroughly reviewed and approved by the Commission and ORS. Full recovery of this investment is mandated under the Base Load Review Act, S.C. Code Ann. §§ 58-33-210 *et seq.,* and the constitutional protections against the taking of private property for public use without just compensation.

As set forth in the Joint Petition, under the Customer Benefits Plan and the No Merger Benefits Plan, SCE&G has proposed to recognize for ratemaking purposes an amount of investment in NND Project assets which is substantially less than the actual amount that it has the lawful right to recover though rates. SCE&G has agreed to do so as a matter of rate mitigation, and only in the context of the approval and adoption of the Customer Benefits Plan or, as a disfavored alternative, the No Merger Benefits Plan and the other terms they contain.

The amounts of NND Project investment both before and after reductions in the form of rate mitigation and before and after the transfer of certain assets that are being placed into service, are clearly set forth in the Joint Petition.

Under all three regulatory plans presented in the Joint Petition, SCE&G will continue to compute its cost of capital based on its pre-impairment capital structure. To do otherwise would be to apply a capital structure that is artificially distorted by amounts required to be written down under generally accepted accounting principles due to rate mitigation or in response to the determination by SCE&G that it cannot represent that it is likely to obtain the full and timely recovery of and on its investment in the NND Project. The recognition of impairments in no way changes the fact that this investment is and lawfully should be fully recoverable as a matter of constitutional law, statutory law and rate regulation.

In addition, recognizing these impairments in computing SCE&G's capital structure would result in a mismatching of SCE&G's capital structure to its cost of capital. SCE&G's cost of capital was determined based on a capital structure comparable to the pre-impairment capital structure and credit ratings consistent with that capital structure. In addition, as SCE&G has indicated in affidavits filed with the PSC, from a financial standpoint a capital structure that reflects rate concessions and impairments is not sustainable financially without impairing SCE&G's creditworthiness.

Under the Base Request, SCE&G does not consent to recognize any reduction in the amount of investment in the NND Project. The amount of investment that SCE&G intends to recover under the Base Request if its rate mitigation plans are not adopted, includes the full amount of its NND Project investment.

RESPONSIBLE PERSONS:

Iris Griffin – SCANA
Byron Hinson - SCANA
Sonali Kripalani – Dominion Energy
Lisa Booth – Dominion Energy