Unitil

EXHIBIT
#1
DE 18-036

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[3] (Pages 071-072 Intentionally Blank)
[4] (Schedule DLC-7 Intentionally Omitted)

Unitil

REVISED

April 18, 2018

BY HAND DELIVERY and E-MAIL

Ms. Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301-2429

Re: DE 18-036 Unitil Energy Systems, Inc.
Petition for Approval of Step Increase and Other Rate Adjustments

Dear Director Howland:

Enclosed for filing on behalf of Unitil Energy Systems, Inc. ("UES" or "Company") are an original and six (6) copies of a Petition for Approval of Step Increase and Other Rate Adjustments. As described in the attached Petition and accompanying testimonies and schedules, the Petition requests approval of a number of rate adjustments, several of which are offsetting, including:

- a 2018 Step Adjustment to reflect recovery of 2017 capital additions;
- a reduction in the revenue requirement to reflect the impact of federal and state corporate tax reductions;
- the termination and removal of the Recoupment portion of the rate increase approved in docket DE 16-384; and
- changes to the Storm Reconciliation Adjustment Factor (SRAF).

In support of the Petition, the filing contains the testimony and schedules of: David L. Chong, Director of Finance and Treasurer for Unitil Service Corp. and Richard L. Francazio, Director of Business Continuity and Compliance for Unitil Service Corp.

This filing also includes the information required by the Settlement Agreement related to earnings sharing and exogenous events. As described in Exhibit DLC-1, the testimony of David L. Chong, there are no rate changes required associated with earnings sharing or exogenous events.

As a result of this filing, a typical 600 kWh residential customer on default energy service will see a monthly bill decrease of ($0.11) or (0.1%). Bill impacts for other rate classes vary based on consumption level and pattern.

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Please do not hesitate to contact me if you have any questions concerning this filing.

Sincerely,

Gary Epler
Attorney for Unitil Energy Systems, Inc.

Enclosures

cc: Donald M. Kreis, Consumer Advocate

BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

	)	
	)	
UNITIL ENERGY SYSTEMS, INC.	)	**DOCKET NO. DE 18-036**
Petitioner	)	
	)	

<u>REVISED</u> PETITION FOR APPROVAL OF STEP INCREASE AND OTHER RATE ADJUSTMENTS

Unitil Energy Systems, Inc., ("UES" or "Company") submits this Petition requesting approval of the New Hampshire Public Utilities Commission ("Commission") of the following:

1) A 2018 Step Adjustment of $3,302,989 effective May 1, 2018 to reflect the recovery of 2017 capital additions of $32,687,415, in accordance with the provisions of paragraph 2.1 of the Settlement Agreement in DE 16-384;

2) A reduction in revenue requirement of $2,244,744, in compliance with Commission Order No. 26,096 in Docket IR 18-001 to reflect the impact of federal and state corporate tax reductions (the "Tax Act");

3) Pursuant to paragraph 2.3 of Settlement Agreement in DE 16-384, removal from the revenue requirement of Recoupment revenue of $1,411,065;

4) Transferring the costs incurred by the Company as a result of the October 2017 wind storm from the MSCR to the Storm Reconciliation Adjustment Factor ("SRAF"); and

6) A reduction in the SRAF of 14.4% on May 1, 2018 after including the October 2017 wind storm costs and accounting for the drop-off of the recovery of the costs of Hurricane Sandy.

In support of its Petition, UES states the following:

Petitioner

UES is a New Hampshire corporation and public utility primarily engaged in the distribution of electricity in the capital and seacoast regions of New Hampshire.

Description of Exhibits

In support of the relief requested in this Petition are the following Exhibits:

Exhibit DLC-1: Testimony and Schedules of David L. Chong.

Exhibit RLF-1: Testimony and Schedules of Richard L. Francazio.

Proposed Tariffs

Unitil Energy plans to make a compliance tariff filing for effect May 1 once rates included in this filing are approved.

Proposed Rate Calculations

Schedule DLC-9 REVISED shows the rate design from current rates to the rates proposed in this filing for each of the following individual adjustments: a) 2018 Step Adjustment; b) adjustments due to the Tax Act; and c) Recoupment.

Bill Impacts

Bill impacts are computed and shown in Schedule DLC-10 REVISED. These reflect the distribution rates and the Storm Recovery Adjustment Factor as proposed in this filing versus currently effective rates. As a result of this filing, a typical 600 kWh residential customer on default energy service will see a monthly bill decrease of ($0.11) or (0.1%). Impacts to other rate classes will be similar, but may vary based on size and consumption pattern.

Conclusion

For all of the foregoing reasons, and as supported in the testimonies and schedules accompanying this filing, UES requests that the Commission grant it the approvals requested in this Petition, and for such other relief as the Commission may deem necessary and proper.

Respectfully submitted,

UNITIL ENERGY SYSTEMS, INC.
By its Attorney:

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April 16, 2018

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UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

DAVID L. CHONG

EXHIBIT DLC-1

REVISED

New Hampshire Public Utilities Commission

Docket No. DE 18-036

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SCHEDULES

Schedule DLC-1	2018 Step Adjustment
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(Schedule DLC-7)	(DELETED)
Schedule DLC-8	NH PUC 2017 F-1
Schedule DLC-9 REVISED	Rate Design
Schedule DLC-10 REVISED	Bill Impacts

I. INTRODUCTION

Q. Please state your name and business address.

A. David L. Chong, 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities?

A. I am Director of Finance and Treasurer for Unitil Service Corp., a subsidiary of Unitil Corporation that provides managerial, financial, regulatory, engineering and other shared services to Unitil Corporation's utility subsidiaries. I am also the Treasurer of Unitil Energy Systems, Inc. (hereinafter referred to as "Unitil Energy" or the "Company") and Unitil Corporation's other utility subsidiaries. My responsibilities are primarily in the areas of financial planning and analyses, regulatory projects, treasury operations and banking relationships.

Q. Please describe your business and educational background.

A. I have approximately sixteen years of professional experience in the energy and utilities industries. From 2001 through 2005, I worked for Exxon Mobil Corporation in various facilities engineering roles with my last position as a Senior Project Engineer. From 2005 through 2008, I worked for RBC Capital Markets Corporation in the energy investment banking group, where I provided corporate finance and mergers and acquisitions advisory services. While at RBC, I raised equity and debt capital on numerous occasions for various energy companies. I also advised on several buy-side and sell-side mergers and acquisitions transactions. From 2008 through 2009, I worked for El Paso Exploration & Production Company in its business development group as an Acquisition & Divestiture Principal. I began working for Unitil Service Corp. in August 2009 as Director of Finance. I hold a Master's Degree in Business Administration from Tulane University and a Bachelor of Science degree in Mechanical Engineering with Honors from the University of Texas at Austin.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the New Hampshire Public Utilities Commission (the "Commission") on various financial, ratemaking and utility regulation matters, including utility cost of service and revenue requirements analysis. I have also testified before the Maine Public Utilities Commission and Massachusetts Department of Public Utilities on similar matters on several occasions.

II. SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present and support Unitil Energy's revenue requirement for its 2018 Step Adjustment based on 2017 capital spending. I also explain and calculate the proposed reduction in distribution rates relating to the recently passed federal tax legislation signed into law by the President of the United States on December 22, 2017. The Tax Cuts and Jobs Act of 2017 (referred to herein as the "Tax Act") substantially reduced the federal tax rate from 34% to 21%. Since income taxes are collected from rate payers as an operating cost, the Company proposes a corresponding reduction in rates to correspond to the lower federal tax rate. Additionally, I also support and explain proposed changes to the Storm Reconciliation Adjustment Factor ("SRAF") and the Major Storm Cost Reserve ("MSCR"). Lastly, I provide calculations and schedules pertaining to the removal of Recoupment, Vegetation Management Program / Reliability Enhancement Plan ("VMP / REP") reconciliation, Earnings Sharing, Exogenous Events, Rate Design and Bill Impacts.

Q. Please summarize the impacts to distribution revenue.

A. The Company is proposing a 2018 Step Adjustment of $3,302,989 to reflect the recovery of 2017 capital additions of $32,687,415. The Company is also proposing a reduction of $2,244,744 to reflect the impact of the Tax Act. Lastly, the Company is removing Recoupment revenue of $1,411,065. All of these issues will be discussed in greater detail throughout this testimony. The below table summarizes these three proposed changes and nets to a zero change in base rates.

2018 Step Adjustment	$3,302,989
Less: Tax Act Revenue Reduction	$2,244,744
Less: Recoupment Removal	$1,411,065
Net Change in Distribution Revenue	**$(352,820)**

Q. Please explain the increase for the 2018 Step Adjustment?

A. The proposed 2018 Step Adjustment of $3,302,989 is for 2017 capital spending and is included in this testimony pursuant to the Settlement Agreement in DE 16-

384. The 2018 Step Adjustment was derived by calculating the revenue requirement associated with 80% of the changes in Net Plant in Service for the period January 1, 2017 through December 31, 2017. Additional details for the 2018 Step Adjustment will be provided later in this testimony.

Q. Please explain the reduction in distribution revenues for the Tax Act?

A. Unitil Energy is complying with Commission Order No. 26,096 in Docket IR 18-001, "Investigation to Determine Rate Effects of Federal and State Corporate Tax Reductions". The Company has calculated a reduction in distribution revenue for the Tax Act of $2,244,744. This calculation is explained in detail below. As the rate reduction will not occur until May 1, 2018 the Company is accruing a Regulatory Liability relating to the Tax Act for the periods January 1, 2018 through April 30, 2018 to properly reflect operating revenues at lower statutory tax rates (per Order No. 26,096 at 2).

Q. Are you proposing any changes to the SRAF?

A. Yes. The Company is proposing that the costs of $1,233,742 from a major wind storm in October 2017 plus associated carrying charges be transferred from the MSCR to the SRAF effective May 1, 2018. Also, on May 1, 2018, the recovery of Hurricane Sandy will terminate. Thus, the net change to the SRAF will be a 14.4% reduction on May 1, 2018 after including the October 2017 wind storm and the drop-off of Hurricane Sandy.

Q. Please explain the reduction in distribution revenues for Recoupment?

A. Pursuant to paragraph 2.3 of Settlement Agreement in DE 16-384, Recoupment revenue in the amount of $1,411,065 is being recovered from customers on a uniform per kWh basis from all classes for services rendered from May 1, 2017 through April 30, 2018. Recoupment revenue will no longer be collected as of May 1, 2018 which results in a reduction to distribution revenue of $1,411,065.

Q. What other topics do you address in your testimony?

A. Later in my testimony, I discuss and quantify the 2017 calendar year VMP / REP reconciliation, Earnings Sharing, Exogenous Events, Rate Design and Bill Impacts. Of importance is the minimal impact that the collective proposals above will have on ratepayers. A typical 600 kWh residential customer on default energy service will see a monthly bill decrease of ($0.11), or (0.1%), with similar impacts to other rate classes.

III. 2018 STEP ADJUSTMENT

Q. What was the Company's forecasted capital spending for calendar year 2017 for the 2018 Step Adjustment in DE 16-384?

A. As described in the pre-filed direct Testimony of Kevin Sprague in DE 16-384 on page 14 of 26 (Bates 246), the 2017 forecasted capital spending was $21,828,456. This was based upon a 5 year capital budgeted forecast that was developed in 2015. The actual 2017 plant additions and cost of removal closed to plant was $32,687,415.

Q. Please explain the major variances for actual capital additions closed to plant compared to the capital spending forecast amount for 2017.

A. The primary difference between the forecasted capital spending and the amount closed to plant in 2017 was the Broken Ground Substation project. The Broken Ground Substation project was marked operationally in service in 2016 and most of the spending was completed by 2016, but the project was not closed to plant until 2017. Approximately $10.8 million of plant additions in 2017 relate to the Broken Ground Substation which was expended during 2014-2017. Similarly, in last year's Step Adjustment, the Kingston Substation was closed to plant in 2016 for a total of $12.2 million of plant additions, but expenditures occurred during the period 2013-2016. Therefore, because of these two large capital projects with spending in multiple years, capital spending and plant additions in any particular year may not necessarily line up.

Q. How is Net Utility Plant derived?

A. Page 1 of Schedule DLC-1 shows Beginning Utility Plant, Plant Additions, Retirements, and Ending Utility Plant on lines 1-4. Plant Additions and Retirements are detailed on Page 2 by FERC account. Then Page 1, lines 5-9 show Beginning Accumulated Depreciation, Depreciation, Retirements, Cost of Removal, and Ending Accumulated Depreciation. The difference between Ending Utility Plant and Ending Accumulated Depreciation results in Ending Net Utility Plant shown on line 10.

Q. What is the change in the Net Utility Plant in Service for calendar year 2017?

A. The Ending Net Utility Plant seen on Page 1 of Schedule DLC-1, Line 10, is $209,795,605. This figure will be the amount filed in the Company's 2017 FERC Form 1. The Beginning Net Utility Plant of $188,269,043, the difference of Line 1 and Line 5, matches the Ending Net Utility Plant from the Settlement Agreement of DE 16-384. Line 11 shows the Change in Net Utility Plant of $21,526,562.

Q. How is the Revenue Requirement derived?

A. The method used to calculate the Revenue Requirement matches the prior year step adjustment as settled upon in DE 16-384. The annual Change in Net Utility Plant provided above is multiplied by a factor of 80% and is shown in line 12. Then, line 12 is multiplied by line 13, pre-tax rate of return, to derive the Return and Taxes on line 14. The Pre-Tax Rate of Return of 10.15% has been updated for the Tax Act and is calculated on Page 5, line 5. Next, Depreciation Expense is calculated on 80% of the annualized depreciation of Plant Additions for 2017. Then, Property Taxes are calculated on 80% of the Change in Net Utility Plant (line 12). A property tax rate of 2.91% was calculated by dividing the latest annualized Property Tax Payments of $6,110,668 by 2017 Net Utility plant of $209,795,605. Finally, Return and Taxes, Depreciation Expense and Property Taxes are added together to arrive at the Revenue Requirement in Line 17.

Q. What is the final Revenue Requirement that you derived?

A. Page 1 of Schedule DLC-1, Line 17, shows the Revenue Requirement of $3,302,989 which is under the cumulative cap for all three step increases of $4.5 million established in DE 16-384 (see paragraph 2.6 of the Settlement Agreement). The Company calculates the remaining revenue requirement cap for the 2019 Step Adjustment to be $341,808 as shown in Line 25. The cap for the 2019 Step Adjustment has largely been affected by the timing of plant closings for the two substation projects discussed earlier.

IV. TAX CUTS AND JOBS ACT OF 2017 RATE REDUCTION

Q. Please explain how the Tax Act impacts the Company?

A. In December 2017, the Tax Act, which included a reduction to the corporate federal income tax rate to 21% effective January 1, 2018, was signed into law. Utilities will now reflect a lower federal income tax provision for collection through cost of service rate making. The Tax Act also eliminated bonus depreciation for capital placed in service after September 27th, 2017. The Modified Accelerated Cost Recovery System was not changed by the Tax Act.

Q. Have you reduced the Company's distribution revenues for the new federal income tax rate as a result of the Tax Act and recent changes in the state income tax rate?

A. The Company has calculated a revenue reduction of $2,244,744 as a result of the lower federal and state income tax rates. The methodology used by the Company to reflect the lower tax rate is a formula specified by the Federal Energy Regulatory Commission in FERC Order 475 (effective June 26, 1987), published when federal tax rates last changed. See Schedule DLC-2. As precedent, this formula is technically sound and properly reflects the reduction in revenue requirements related to a lower income tax provision. Schedule DLC-3, Line 13, shows a revenue reduction of $2,199,753 pertaining to the Company's last base rate case (Docket DE 16-384). This amount is calculated by applying the FERC formula to the pro forma income taxes to the Company's pro forma 2015 test year cost of service after all adjustments and rate relief awarded in that proceeding. This formula encompasses both the change in federal and state income tax rates. This methodology was also used for Unitil Energy's sister affiliate, Northern Utilities, Inc. - Maine Division, in its base rate case approved in Docket 2017-00065. This methodology has been agreed to by the Company's affiliate Northern Utilities, Inc., the Commission Staff and the Office of Consumer Advocate in the Settlement Agreement which is pending approval by the Commission in Docket DG 17-070. Schedule DLC-3 also shows a revenue reduction of $44,991 (Line 17) pertaining to the 2017 Step Adjustment (reflecting 2016 capital spending) which is calculated by taking the original 2017 Step Adjustment less the revenue requirement for the 2017 Step Adjustment calculated with the new income tax rates. See Schedule DLC-4. Schedule DLC-3, Line 18, shows the grand total revenue reduction for the lower tax rates of $2,244,744.

Q. What is the proposed effective date of the rate change?

A. As directed by the Commission in Order No. 26,096, the Company has recognized a Regulatory Liability of $769,342 as shown in Schedule DLC-5 to reflect reduced rates from January through April 2018 as a result of the Tax Act. This amount will be refunded to customers through the Company's External Delivery Charge (EDC) and included in the annual reconciliation of the EDC, to be filed on or about June 15, 2018, for effect on August 1, 2018.

Q. Have you revalued the Accumulated Deferred Income Tax balance for the year ended December 31, 2017?

A. In conformity with Generally Accepted Accounting Principles ("U.S GAAP" [ASC 740]), the tax rate reduction also requires a revaluation (downward) of the Company's net Accumulated Deferred Income Tax ("ADIT") liabilities on its balance sheet as of December 31, 2017 to reflect a 21% federal income tax rate and a 7.9% state income tax rate. The excess ADIT liabilities as of December 31, 2017 have been recognized by the Company as a Regulatory Liability for U.S. GAAP and regulatory accounting purposes in future rate proceedings. The excess ADIT reflects the difference between the historical recognition of income taxes for book normalization at a corporate income tax rate of 34% which was the federal statutory tax rate for the Company prior to the passage of the Tax Act and the new federal income tax rate of 21%. The Regulatory Liability is included in the Company's rate base along with the adjusted (lower) net ADIT liability balance, so there is no initial net change to rate base.

Q. What will become of the excess ADIT balance?

A. The Company proposes to resolve the flow back of distribution-related excess ADIT to ratepayers during its next base rate case. Any changes to ADIT should coincide with changes in the other components of rate base used for setting base rates. Clearly, the best time to reflect these changes is in a distribution rate case when all parties have the opportunity to fully examine the changes. This is consistent with the way rate base is updated in rate cases. Importantly, rate base is not reconciled from year to year in the periods between rate cases, but is only updated when a new rate case is filed. As such, there are material portions of excess ADIT that are from capital spending that are not reflected in rate base and current rates. Excess ADIT reflects year-end 2017 utility assets, but the Company's last base rate case utilized a 2015 test year. Accordingly, a flow back of 2017 excess ADIT would not be properly matched with base rates currently in place. While the Company has step adjustments for capital additions, they are not fully inclusive for all spending. Furthermore, the step adjustments do not reflect deferred taxes, nor do they roll forward the deferred tax position of its 2015 assets from its last base rate to 2017 which would be necessary to reflect the Company's current rate base in rates. In conclusion, the Company believes there is not a mathematically correct way to match excess ADIT with its rate base currently reflected in rates without a full base rate proceeding with a 2017 test year.

Q. Do you have any other concerns about the Tax Act?

A. The Company is concerned about the impact on cash and funds from operations. The reduced base rates per the Tax Act will reduce collections and stress the Company's credit ratios that are used by credit agencies to determine credit worthiness. The Company estimates that its funds from operations will be reduced approximately 8% with a negative impact of 1.5% to its funds from operations-to debt ratio. With lower funds from operations, the Company's financing requirements will increase with higher borrowings and debt leverage, all else being held equal. The Company believes that the Tax Act has certain negative consequences for utilities as compared to other industries, and expects the required returns of both equity and debt investors to increase as a result of the Tax Act.

V. STORM RECONCILIATION ADJUSTMENT FACTOR

Q. Are you proposing an increase to the SRAF?

A. Yes, as outlined in the testimony of Mr. Francazio (Exhibit RLF-1), the Company experienced a significant wind storm in October 2017. The capitalized cost of the storm is currently in the MSCR, but the Company believes it should be removed from there and amortized and collected through the SRAF mechanism effective May 1, 2018.

Q. **What was the capitalized cost of this storm?**

A. The total cost of the October 2017 wind storm was $1,233,742 and was deferred in the MSCR fund.

Q. **Does the Company believe this should be considered a major storm that qualifies for the SRAF?**

A. Yes. Mr. Francazio further describes and justifies why this storm is appropriate for the SRAF.

Q. What is the Company's specific cost recovery proposal?

A. The Company seeks recovery of the October 2017 wind storm costs through an adjustment to its SRAF effective May 1, 2018. The Company proposes to recover these costs over a five year period with carrying charges calculated at 5.20%, the annual rate equaling the Company's currently approved cost of debt, net of deferred taxes reflecting the Tax Act.

Q. Did the Company consider adding these costs to its MSCR?

A. Yes. However, the MSCR was not designed to include low frequency storms that are extraordinary in magnitude, such as this storm. The current reserve amount of $800,000 annually, was set at a level to deal with more frequent storms that are generally not considered to be extraordinary in magnitude.

Q. **Why does the Company propose to recover these costs over five years?**

A. The Company proposes to recover these costs over five years consistent with the time period of recovery approved for previous storms (Tropical Storm Irene, the October Snowstorm, and Hurricane Sandy). This proposal provides the Company with a reasonable timeframe to reduce the deferred balance while providing for reasonable bill impacts. In this instance, the net change in the SRAF is a decrease because cost recovery of Hurricane Sandy ends on May 1, 2018.

Q. What is the proposed adjustment to the SRAF?

A. As shown on Schedule DLC-6, Page 1 of 3, the proposed rate adjustment is $0.00023 per kWh effective May 1, 2018.

Q. Is the Company currently recovering other storm costs through the SRAF?

A. Yes. The costs of the December 2008 ice storm and February 2010 wind storm are being recovered through the current SRAF over a period of eight years from May 2011 through April 2019 at a rate of $0.00096 per kWh. The cost of Hurricane Sandy is being recovered through the SRAF over a period of five years at a rate of $0.00043 per kWh, and is set to terminate effective April 30, 2018. The total SRAF proposed for effect May 1, 2018 is $0.00119 per kWh. This factor reflects termination of the recovery of Hurricane Sandy, continuing recovery of the costs associated with the December 2008 ice storm and February 2010 wind storm, and adding recovery of the costs from the October 2017 wind storm. The net effect to the SRAF is a decrease of $0.00020 per kWh, or a reduction of 14.4% on May 1, 2018, even after including this October 2017 wind storm.

Q. Will the Company track the account balance of these prior storms separately from the account balance of the October 2017 wind storm?

A. Yes. The recoveries made through the SRAF will be allocated to the prior storms and the October 2017 wind storm based on the proportion of the rate as specified in the Company's tariff, Schedule SRAF (i.e., \$0.00096/\$0.00119 or 80.7% will be charged against the costs from the December 2008 ice storm and February 2010 wind storm and \$0.00023/\$0.00119 or 19.3% will be charged against the costs from the October 2017 wind storm).

Q. Please describe Schedule DLC-6.

A. Page 1 of Schedule DLC-6 shows the calculation of the rate based on an annual levelized cost divided by actual kWh sales for the 12 month period ending December 31, 2017. Page 2 shows the costs, including carrying charges, recovered on a levelized basis over a period of five years beginning May 1, 2018. Page 3 shows the calculation of the beginning balance, including carrying charges, to be recovered. The methodology for calculating the rate is the same as used in previous storm recovery proposals.

Q. Will the reconciliation of costs and revenues be performed on a monthly basis?

A. Yes. As discussed above, the Company will apply an allocated portion of actual revenue from the SRAF to the May 1, 2018 balance. Carrying charges will be calculated monthly based on the average monthly account balance.

Q. Has the Company filed any tariff changes associated with this proposal?

A. A redline and clean version of the Company's tariff, Schedule SRAF, is provided to the cover letter of this filing. If approved, the Company will also update its SRAF in its Summary of Delivery Service Rates tariff page through a compliance filing.

Q. What is the bill impact of this proposed rate change?

A. Based on the decrease to the SRAF of $0.00020 per kWh, a residential customer on Default Service using 600 kWh will see a bill decrease of $0.12 or 0.1%.

VI. RECOUPMENT, STORM RESILIENCY PROGRAM, AND VMP / REP RECONCILIATION

Q. Please explain the reduction in the revenue requirement for Recoupment?

A. Recoupment revenue in the amount of $1,411,065 was recovered from customers on a uniform per kWh basis from all classes for services rendered from May 1, 2017 through April 30, 2018. As provided in the Settlement Agreement in DE 16-384, Recoupment revenue will no longer be collected as of May 1, 2018. That will result in a reduction to distribution revenue of $1,411,065.

Q. Have you calculated 2017's reconciliation of vegetation management program / reliability enhancement plan O&M expenditures?

A. Yes. As required by Section 7.2 of the DE 16-384 Settlement, Unitil Energy will continue to reconcile actual VMP and REP program O&M expenses for future calendar years to an amount of $4,858,739. For calendar year 2017, the Company spent $5,290,789 in VMP expense, $71,143 of REP expenses related to VMP, and $220,000 for reliability inspection and maintenance for a grand total of $5,581,932. In calendar year 2017, the Company collected $754,016 from Fairpoint Communications, providing for a net total expenditure of $4,827,916. The net expenditure of $4,827,916 is subtracted from the $4,858,739 for a total over-collection of $30,823, which will be credited to the Company's External Delivery Charge mechanism on May 1, 2018. Historically, the Company has credited the VMP / REP reconciliation since 2014 when it began. Since 2014, the Company has credited the External Delivery Charge for VMP / REP reconciliations 5 out of 5 years, for a total credit of $2,254,232.

VII. EARNINGS SHARING AND EXOGENOUS EVENTS

Q. What was the Company's return on equity in 2017 per its F-1? Does the Company qualify for earnings sharing in 2017?

A. The Company's return on equity for 2017 was 8.09% as shown in Schedule DLC-8. The Company does not qualify for earnings sharing in 2017.

Q. Were there exogenous events in 2017?

A. The Company believes that the Tax Act would qualify for an exogenous event under its Settlement Agreement in Docket DE 16-384 which would imply a rate effective date of May 1, 2018. However, the Company has implemented the Tax Act revenue reduction effective January 1, 2018 in accordance with NH PUC Order No. 26,906. The Company does not believe there were any other exogenous events in 2017.

VIII. RATE DESIGN

Q. Please explain the rate design for each component a) 2018 Step Adjustment, b) adjustments due to the Tax Act and c) Recoupment.

A. Schedule DLC-9 shows the rate design from current rates to the rates proposed in this filing for each of the individual adjustments. The current rates in column (c) do not reflect the recoupment rate of $0.00116 per kWh since it was not shown that way with the original settlement in DE 16-384. Rather, there is a line at the bottom of the schedule showing the rate and $ and their removal on May 1, 2018. Columns (d) – (f) show the rate design for the step adjustment of $3,302,989 which is done in accordance with the settlement and applied equi-proportionally to all rate components except the fixed transformer ownership credits. The net of the step adjustment and the removal of the recoupment is $1,891,924. Finally, the rate design for the Tax Act is shown in columns (j) – (l). The adjustment amount of -$2,244,744 is applied proportionally to each rate class in such a way that customer charges and fixed transformer ownership discounts are left unchanged. The decrease is applied to distribution energy charges, demand charges and outdoor lighting luminaire charges such that each class received the same overall percent increase. The net of all the changes proposed effective May 1, 2018 is $(352,820).

Q. Is the Company filing a revised Summary of Delivery Rates tariff schedule, pages 4 and 5, at this time?

A. No. Unitil Energy plans to make such a filing for effect May 1 as part of a compliance tariff filing once rates included in this filing are approved.

IX. BILL IMPACTS

Q. What are the class bill impacts proposed for May 1, 2018?

A. Bill impacts are computed and shown in Schedule DLC-10. These reflect the distribution rates and the Storm Recovery Adjustment Factor as proposed in this filing versus currently effective rates. As a result of this filing, a typical 600 kWh residential customer on default energy service will see a monthly bill decrease of ($0.11) or (0.1%). Impacts to other rate classes will be similar, but may vary based on size and consumption pattern.

X. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

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May 1, 2018 Step Adjustment

Line No.	Description	Investment Year 2017
	Rate Effective Date	5/1/2018
	Utility Plant:	
1	Beginning Utility Plant	$ 294,443,220
2	Plant Additions	32,158,460
3	Retirements	(2,387,563)
4	Ending Utility Plant	324,214,118
5	Beginning Accumulated Depreciation	106,174,178
6	Depreciation	11,128,490
7	Retirements	(2,387,563)
8	Cost of Removal and Salvage	(496,592)
9	Ending Accumulated Depreciation	114,418,513
10	Ending Net Utility Plant	$ 209,795,605
	Revenue Requirement:	
11	Change in Net Plant	$ 21,526,562
12	80% of Change in Net Plant	17,221,249
13	Pre-Tax Rate of Return	10.15%
14	Return and Taxes	1,748,493
15	Depreciation Expense on 80% of Plant Additions (1)	1,053,358
16	Property Taxes on 80% Change in Net Plant (2)	501,138
17	Revenue Requirement	$ 3,302,989
18	**Rate Cap Limit:**	
19	Revenue Requirement	$ 3,302,989
20	May 1, 2017, 2018 & 2019 Step Adjustment Revenue Requirement Cap	$ 4,500,000
21	Less: May 1, 2017 Step Adjustment Revenue Requirement	900,194
22	Add: Tax Rate Reduction to May 1, 2017 Step Adjustment	44,991
23	Remaining May 1, 2018 & 2019 Step Adjustment Revenue Requirement Cap	$ 3,644,797
24	Allowable Revenue Requirement (Min of Line 19 or 22)	$ 3,302,989
25	Remaining May 1, 2019 Step Adjustment Revenue Requirement Cap	$ 341,808

Notes:
(1) See Annualized Depreciation from page 4
(2) 2.91% rate (2017 Property Taxes of $6,110,668 / 2017 Net Utility Plant of $209,795,605)

2017 Gross Plant Detail

Description	Beginning Balance	Additions	Retirements	Ending Balance
301-00 Organization-E	380	-	-	380
303-00 Intangible Software-5 Yea-E	4,050,981	455,710	-	4,506,691
303-01 Intangible Software-3 Yea-E	87,196	-	-	87,196
303-02 Intangible Software-10 Yea-E	2,307,249	2,398,484	-	4,705,733
343-00 Prime Movers-E	56,575	-	-	56,575
353-00 Transmission Station Equi-E	-	-	-	-
360-01 ROW - Distribution-E	991,116	-	-	991,116
360-02 ROW - Distribution-E	1,674,812	-	-	1,674,812
361-00 Distribution Structures-E	167,773	2,005,843	-	2,173,616
362-00 Distribution Station Equi-E	36,463,670	9,429,736	(117,448)	45,775,957
364-00 Distribution Poles, Tower-E	57,227,150	4,643,618	(302,782)	61,567,986
365-00 Distribution Overhead Con-E	73,578,306	5,686,904	(511,652)	78,753,557
366-00 Distribution Underground -E	1,870,543	53,255	(2,274)	1,921,524
367-00 Distribution Underground -E	18,972,752	1,010,135	(101,085)	19,881,802
368-00 Distribution Line Transfo-E	25,112,809	1,411,172	(292,212)	26,231,769
368-01 Transformer Installations-E	19,443,103	1,115,120	(166,950)	20,391,273
369-00 Distribution Services-E	21,070,632	1,439,916	(69,261)	22,441,287
370-00 Distribution Meters-E	9,960,229	513,030	(334,282)	10,138,977
370-01 Meter Installation-E	4,519,509	521,731	(107,360)	4,933,880
371-00 Installations on Customer-E	2,054,660	178,376	(93,396)	2,139,641
373-00 Street Lights & Signal Sy-E	3,279,130	117,749	(75,996)	3,320,883
373-01 Street Lights & Signal Sy-E	-	-	-	-
389-00 General & Misc. Land-E	18,620	-	-	18,620
390-00 Structures-E	3,809,477	289,084	-	4,098,562
390-01 General & Misc. Structure-E	-	-	-	-
391-01 Office Furniture & Fixtur-E	271,671	7,111	-	278,782
391-03 Computer Equipment-E	-	-	-	-
392-00 Transportation Equipment-E	1,073,695	-	-	1,073,695
393-00 Stores Equipment-E	79,908	-	-	79,908
394-00 Tools, Shop and garage Eq-E	1,615,777	293,470	-	1,909,247
395-00 Laboratory Equipment-E	823,462	29,310	-	852,772
397-00 Communication Equipment-E	3,759,091	558,706	(212,864)	4,104,932
398-00 Miscellaneous Equipment-E	102,943	-	-	102,943
399-00 Other Intangible Plant-E	-	-	-	-
Grand Total	294,443,220	32,158,460	(2,387,563)	324,214,118

2017 Accumulated Depreciation Detail

Description	Beginning Balance	Provision	Retirements	Cost of Removal	Salvage	Ending Balance
301-00 Organization	-	-	-	-	-	-
303-00 Intangible Software-5 Year	3,578,054	287,861	-	-	-	3,865,915
303-01 Intangible Software-3 Year	87,196	-	-	-	-	87,196
303-02 Intangible Software-10 Year	952,715	250,712	-	-	-	1,203,428
343-00 Prime Movers	21,702	3,774	-	-	-	25,475
350-01 ROW - Transmission	-	-	-	-	-	-
350-02 ROW ¿ Transmission	-	-	-	-	-	-
352-00 Transmission Structures	-	-	-	-	-	-
353-00 Transmission Station Equipme	-	-	-	-	-	-
354-00 Transmission Towers & Fixtur	-	-	-	-	-	-
355-00 Transmission Poles & Fixture	-	-	-	-	-	-
356-00 Transmission Overhead Conduc	-	-	-	-	-	-
360-01 ROW - Distribution	-	-	-	-	-	-
360-02 ROW ¿ Distribution	-	-	-	-	-	-
361-00 Distribution Structures	136,320	10,078	-	-	-	146,398
362-00 Distribution Station Equipme	8,136,801	1,035,796	(117,448)	(5,888)	-	9,049,261
364-00 Distribution Poles, Towers &	22,247,770	2,159,482	(302,782)	(154,558)	3,388	23,953,300
365-00 Distribution Overhead Conduc	22,381,501	2,722,419	(511,652)	(239,210)	5,553	24,358,610
366-00 Distribution Underground Con	590,932	38,660	(2,274)	(101)	0	627,217
367-00 Distribution Underground Con	5,599,232	495,743	(101,085)	(33,020)	3,292	5,964,162
368-00 Distribution Line Transforme	9,708,678	760,045	(292,212)	(8,560)	1	10,167,952
368-01 Transformer Installations	4,858,773	567,334	(166,950)	(434)	-	5,258,722
368-02 Transformers Installations	-	-	-	-	-	-
369-00 Distribution Services	14,410,056	1,217,296	(69,261)	(48,480)	1,066	15,510,678
370-00 Distribution Meters	3,983,736	491,775	(334,282)	(243)	-	4,140,985
370-01 Meter Installation	681,280	224,775	(107,360)	-	-	798,695
370-02 Meter Installations	-	-	-	-	-	-
371-00 Installations on Customers P	448,681	158,390	(93,396)	(9,109)	7,788	512,355
373-00 Street Lights & Signal Syste	2,273,055	258,017	(75,996)	(14,914)	11,274	2,451,436
373-01 Street Lights & Signal Syste	-	-	-	-	-	-
389-00 General & Misc. Land	-	-	-	-	-	-
390-00 Structures	1,515,037	79,738	-	-	-	1,594,775
390-01 General & Misc. Structures	863	-	-	-	-	863
391-01 Office Furniture & Fixtures	(138,394)	15,873	-	-	-	(122,521)
391-03 Computer Equipment	4,346	-	-	-	-	4,346
392-00 Transportation Equipment	1,045,145	-	-	-	-	1,045,145
393-00 Stores Equipment	55,412	2,685	-	-	-	58,097
394-00 Tools, Shop and garage Equip	694,581	60,421	-	-	-	755,002
395-00 Laboratory Equipment	362,549	32,253	-	-	-	394,803
397-00 Communication Equipment	2,454,746	250,340	(212,864)	(14,438)	-	2,477,785
398-00 Miscellaneous Equipment	83,411	5,024	-	-	-	88,434
399-00 Other Tangible Property	-	-	-	-	-	-
Grand Total	106,174,178	11,128,490	(2,387,563)	(528,955)	32,363	114,418,513

Annualized Depreciation by FERC Account

Description	Additions	Depreciation Rate	Annual Depreciation
303-00 Intangible Software-5 Yea-E	455,710	20.00%	91,142
303-02 Intangible Software-10 Yea-E	2,398,484	10.00%	239,848
361-00 Distribution Structures-E	2,005,843	2.45%	49,143
362-00 Distribution Station Equi-E	9,429,736	2.60%	245,173
364-00 Distribution Poles, Tower-E	4,643,618	3.70%	171,814
365-00 Distribution Overhead Con-E	5,686,904	3.64%	207,003
366-00 Distribution Underground -E	53,255	2.04%	1,086
367-00 Distribution Underground -E	1,010,135	2.55%	25,758
368-00 Distribution Line Transfo-E	1,411,172	3.00%	42,335
368-01 Transformer Installations-E	1,115,120	2.89%	32,227
369-00 Distribution Services-E	1,439,916	5.67%	81,643
370-00 Distribution Meters-E	513,030	5.00%	25,652
370-01 Meter Installation-E	521,731	5.00%	26,087
371-00 Installations on Customer-E	178,376	7.56%	13,485
373-00 Street Lights & Signal Sy-E	117,749	7.79%	9,173
390-00 Structures-E	289,084	2.08%	6,013
391-01 Office Furniture & Fixtur-E	7,111	5.83%	415
394-00 Tools, Shop and garage Eq-E	293,470	3.64%	10,682
395-00 Laboratory Equipment-E	29,310	3.90%	1,143
397-00 Communication Equipment-E	558,706	6.60%	36,875
Grand Total	32,158,460	4.09%	1,316,698

Pre-Tax Rate of Return
December 31, 2015 Pro Forma

Line No.	Description	Proformed Amount	Weight	Cost of Capital	Weighted Cost of Capital	Tax Factor(1)	Pre-Tax Cost
1	Common Stock Equity	$ 77,284,950	50.97%	9.50%	4.84%	1.3744	6.65%
2	Preferred Stock Equity	189,800	0.13%	6.00%	0.01%		0.01%
3	Long Term Debt	74,000,000	48.80%	7.15%	3.49%		3.49%
4	Short Term Debt	161,783	0.11%	1.54%	0.00%		0.00%
5	Total	$ 151,636,533	100.00%		8.34%		10.15%

Notes:
(1) New tax factor calculated using a Federal Tax Rate of 21% and State Tax Rate of 7.9% (effective tax rate of 27.241%)

ATTACHMENT A

Order No. 475

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 35 and 389

Electric Utilities; Rate Changes Relating to Federal Corporate Income Tax Rates for Public Utilities

[Docket No. RM87-4-000; Order No. 475]

52 FR 24987

July 2, 1987

EFFECTIVE DATE: June 26, 1987.

FOR FURTHER INFORMATION CONTACT: Thomas J. Lane, Office of the General Counsel, Federal Energy Regulatory Commission, 825 North Capitol Street, NE., Washington, DC 20426, (202) 357-8530.

TEXT: Issued: June 26, 1987.

ACTION: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: In the Tax Reform Act of 1986 Congress reduced the maximum Federal corporate income tax rate from 46 percent to 34 percent, effective July 1, 1987. The Federal Energy Regulatory Commission is adopting an abbreviated rate filing procedure that public utilities may use to reduce their rates to reflect this decrease.
SUPPLEMENTARY INFORMATION:

I. Introduction

The Tax Reform Act of 1986 n1 signed on October 22, 1986, significantly lowered the Federal corporate income tax rate from 46 percent to 34 percent. The Federal Energy Regulatory Commission (Commission) is adopting a voluntary, abbreviated rate filing procedure that will allow electric public utilities to file for certain rate decreases under section 205 of the Federal Power Act (FPA), n2 to reflect this decrease in the Federal income tax tate. n3

n 1 *I.R.C. 1-7872* (1986).

n 2 *16 U.S.C. 824d* (1982).

n 3 Although the reduction in the Federal corporate income tax rate impacts on natural gas and oil pipelines, this rule is limited to electric public utilities. Natural gas pipeline companies' rates will automatically be adjusted since tax trackers have been included in the majority of the natural gas pipeline companies' rate settlements. Changes in oil pipeline rates will be made on a case-by-case basis.

The reduction in rates will be based on a formula using data provided by the utility in its most recent rate filing. Under this procedure, the Commission will consider only the reduction in the Federal corporate tax rate in establishing the new rate. Any other issues which may be raised in the rate filing will be dismissed without prejudice.

For utilities which do not voluntarily reduce their rates either through this abbreviated procedure or through general rate changes filings, the Commission intends to undertake a general review of their rates, and where appropriate, to institute formal investigations under section 206 of the FPA n4 on the basis that rates reflecting the 46 percent tax rate or other previously authorized cost allowances may no longer be just and reasonable. n5

n 4 *16 U.S.C. 824e* (1982).

n 5 Recently, the Commission instituted 206 proceedings involving the formula rates of electric utilities. *See,* EL87-21-000 Yankee Atomic Electric Company, EL87-22-000 Vermont Yankee Nuclear Power Corporation, EL87-23-000 Connecticut Yankee Atomic Power Company, EL87-30-000 Connecticut Light & Power Company.

II. Background

In response to the Tax Reform Act, the Commission, on March 12, 1987, published a Notice of Proposed Rulemaking (NOPR) n6 which proposed an abbreviated filing procedure that would allow public utilities to voluntarily reduce their rates to account for this reduction in the Federal tax rate. n7 The NOPR proposed two methods of determining the rate reduction. The primary option would permit a utility to reflect the reduction in the tax rate through a formula reduction to its existing rates. The formula would rely on data supplied by the utility inits most recent rate filing. An alternative approach was also suggested under which rates would be reduced using a generically determined fixed percentage reduction to the demand charge component of a utility's exisitng rates.

n 6 Rate Changes Relating to Federal Corporate Income Tax Rate for Public Utilities, *52 FR 8616* (Mar. 19, 1987). FERC Stats. and Regs. para. 32,437.

n 7 Fifty-two commenters responded to the NOPR. The list of commenters is contained in Appendix A.

The NOPR proposed to preclude a utility from using the abbreviated filing procedure if it had a rate change application pending before the Commission on a date certain; if it had an accepted tariff providing for automatic adjustments to reflect changes in the Federal tax rate; or if it already had rates in effect which reflected the reduced Federal income tax rate.

The NOPR stated that if a utility wished to reflect in its rates other changes created by the Tax Reform Act or by other cost elements, instead of the abbreviated procedure, it should file a rate change application under section 205 of the FPA. The Commission also proposed that if a utility failed to file for rate reductions, the Commission might institute a proceeding requiring the utility to show cause why its unadjusted rates are just and reasonable under section 206 of the FPA. The NOPR also proposed that such an investigation might not be limited to issues relating to the Tax Reform Act, and might include all components of the utility's rates.

A. Overview

The Commission is concerned that large overcollections on an industry-wide basis may occur unless rates are reduced promptly to reflect the new tax rate since the reduction in the tax rate affects all utilities. The Commission is adopting a generic approach to address this concern. Through a generic reduction in rates based on a formula, a utility would be able to adjust for changes in the corporate tax rate by using an expedited procedure that would provide consumers immediate rate relief.

The Commission realizes that a formula reduction in rates may not be appropriate for all utilities under all circumstances. Therefore, a utility that chooses not to use the abbreviated procedure established in this rule may agree to a settlement with its customers, file a general section 205 rate change application, or if a utility finds that no rate reduction is warranted, it may elect to do nothing.

The Commission encourages settlement agreements and will look favorably on any proposed settlements that take into account the impact of the reduction in the tax rate.

Under a full section 205 rate change application, a utility may raise any other factors which might counterbalance the tax rate reduction. Under a full rate change application customers may also raise any relevant issues.

If a utility concludes that no rate decrease is warranted, it may refrain from filing any rate reduction. If the Commission institutes a section 206 proceeding, a utility may raise relevant issues to show that its unadjusted rates are just and reasonable.

B. Other Tax and Cost Considerations.

In the NOPR, the Commission identified three provisions of the Tax Reform Act that might affect public utilities on an industry-wide scale. These were changes in the depreciation rates, loss of investment tax credits and the reduction in the Federal income tax rate. The Commission stated in the NOPR that changes in liberalized depreciation and the loss of investment tax credits would have little immediate effect on a utility's rates. n8 It therefore concluded that the only changes that a utility should adjust immediately would be those to reflect the reduction in the Federal corporate income tax rate.

n 8 Changes in tax depreciation have little immediate impact on the calculation of income tax allowable because of the Commission's tax normalization policy. Under normalization the calculation of allowable income tax expense is based upon the amount of book depreciation taken, not tax depreciation. The amount of book depreciation is not affected by the Tax Reform Act. *See 18 CFR 35.25*. "Regulations Implementing Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes," Order No. 144, *46 FR 26613* (May 14, 1981), FERC Stats. and Regs. [Regulations Preambles, 1977-1981] para. 30,254 (May 6, 1981). Similarly, loss of investment tax credits will also have a minimal effect on a utility's revenue requirements. Under current regulatory policy, the benefits of investment tax credits are shared between the ratepayer and the stockholders of the regulated entities. The ratepayer benefits by either receiving the time value of the unamortized investment tax credit or the annual amortization amount, but not both, depending upon the optional treatment elected by the utility. The rate reducing effects of previously generated investment tax credits will continue until fully amortized.

Many commenters faulted the Commission for concentrating solely on the reduction of the tax rate. n9 They argued that other provisions of the Tax Reform Act offset this decrease. n10

n 9 *See, e.g.,* Utah Power and Light Company, Philadelphia Electric Company, Kentucky Utilities Company, Electric Utilities, Public Service Electric and Gas Company, Colorado Public Utilities Commission, Public Service Company of Colorado, Sierra Pacific Power Company.

n 10 In addition to elimination of investment tax credits and changes in depreciation other provisions of the TRA cited by commenters that addressed this issue were:

-- Recognition of unbilled revenues.

-- Capitalization of certain construction overheads.

-- Taxability of contributions in aid of construction.

-- Alternative minimum tax provisions.

-- Timing of deduction for sales tax, property tax, and employee benefits.

-- Elimination of accrual accounting for accrued vacation pay and reserve for bad debts.

The Commission recognizes that many of the aspects of the Tax Reform Act cited by the commenters may have an impact on a utility's cash flow. The effect, however, will differ widely from utility to utility depending upon its particular circumstances, and therefore would be inappropriate for a generic formula, which could not account for all the changes made by the Act and their effects on each utility. The one aspect of the Tax Reform Act that will have a significant effect on the rates of electric utilities on an industry-wide basis is the corporate tax rate reduction.

The Commission has determined that, to reflect this one change, the income tax component of rates under the Commission's ratemaking model should be reduced by nearly 40 percent. n11 Through this procedure, the Commission is enabling a public utility to voluntarily reduce its rates without having to file a full rate change application.

n 11 The percentage change in the income tax component of a jurisdictional company's revenue requirement due to a reduction in the Federal corporate income tax rate can be measured by the incremental change in the "income tax factor." This factor, expressed as the Federal tax rate divided by one minus the Federal tax rate, is 0.85185 at the 46 percent rate and 0.51515 at the 34 percent rate. Thus, the 12 percentage point reduction in the Federal tax rate translates to nearly a 40 percent reduction in a jurisdictional company's income tax allowance.

Some commenters suggested that the Commission consider changes in state income taxes. n12 Others urged the Commission to take into account other increases in cost components which might affect a utility's rates. n13 The Commission disagrees. The purpose of this final rule is to provide utilities with a simple mechanism to voluntarily reduce rates to reflect the reduction in the Federal tax rate. Consideration of these other suggested factors would unnecessarily complicate the abbreviated filing and delay rate relief.

n 12 *See* Utah Power and Light Company, Idaho Power Company (state tax increases), Cities and Villages of Algoma, *et al.* (state tax decreases).

n 13 *See, e.g.,* Central Illinois Public Service Company, Utah Power and Light Company.

C. Filing Options

The NOPR requested comments on two proposed abbreviated filing methods, and invited suggestions on any other alternatives. The first alternative proposed in the NOPR was a formula reduction in rates, based on data supplied by the utility in its most recent rate filing. Under the alternative option, rates would be reduced automatically, for all utilities, using a fixed percentage reduction to the demand charge.

Most commenters (even those opposed to the rulemaking) favored the formula approach over a fixed percentage reduction. n14 Most utilities favored retaining both approaches, which would enable the filing utility to select the methodology most suited to its particular situation. n15 Some utilities also suggested that the Commission provide many abbreviated filing options. n16

n 14 *See, e.g.,* Public Service Company of Oklahoma, Borough of Madison, New Jersey, Consumer Power Company, Saffer Utility Consultants, Inc.

n 15 *See, e.g.,* Carolina Power and Light Company, Electric Utilities, Arizona Public Service Company.

n 16 *See, e.g.,* American Electric Power Service Corporation, Edison Electric Institute, Southwestern Electric Power Company.

The Commission is adopting only the formula alternative. The Commission agrees with many of the commenters that a formula reduction has certain advantages over a fixed percentage reduction. n17 While both may be simple, the formula approach is utility-specific. As such, it can more readily accommodate a utility's specific circumstances and, therefore, more closely approximates the actual cost-to-service impact of the lower tax rate.

n 17 *See, e.g.,* Department of Water Resources of the State of California, Coast Electric Power Association, *et al.*

Commenters also cited problems with the fixed percentage option. n18 Since it is not utility-specific, but calls for an across-the-board reduction for all utilities, it may be imprecise. In fact, it may produce excessive reductions for some utilities and allow others to receive a windfall. The Commission believes that the fixed percentage approach would be unfair to both the utility and the ratepayers. Additionally, these commenters faulted the method by which the Commission determined the fixed reduction percentage. The percentage reduction proposed in the NOPR was based on a sampling of eight rate filings which resulted in a five to eight percent reduction in the nonvariable portion of a utility's revenue requirement. Commenters argued that the sampling was too small and was not representative of the industry. The Commission recognizes that there are approximately 175 utilities subject to the Commission's jurisdiction. The Commission agrees that a determination of an appropriate fixed percentage reduction would require extensive sampling. Furthermore, the Commission believes that using any fixed percentage reduction would not yield as accurate a result as a formula reduction.

n 18 *See, e.g.,* Southwestern Electric Power Company, Public Systems.

In view of the disadvantages of the fixed percentage approach, the Commission must reject the argument that a utility should have the option of using either the formula method or the fixed percentage method.

Some commenters wanted the Commission to adopt numerous filing options. 1 n9 Others suggested that the Commission establish some type of simplified procedure that a utility could use to show that its unadjusted rates remained justified. 2 n0 The Commission believes that multiple filing options or additional procedures would be unduly cumbersome. Allowing utilities to make simplified showings that their rates are just and reasonable also poses evidentiary problems, since a utility would be free to selectively supply the Commission with data in support of its case. A more appropriate forum to make such a showing is a proceeding under either section 205 or 206 of the FPA.

n 1 9 *See, e.g.,* Public Service Company of Oklahoma, Edison Electric Institute.

n 2 0 *See, e.g.,* Pennsylvania Power & Light Company, Central Vermont Public Service Corporation, Public Service Company of New Mexico.

D. The Formula

The adopted formula is:

$$K = \frac{D - D(E/F)}{I}$$

Where

D=Composite income taxes allowable included in rates in effect on the date that the change in the Federal corporate income tax rate becomes effective.

E=Composite income tax factor using the new Federal corporate income tax rate and the effective state income tax rate from the rate application docket upon which existing rates are based. This is computed by the following formula:

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composite marginal income tax rate
-composite marginal income tax rate
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F=Composite income tax factor using the old Federal corporate income tax rate. This is computed by the same formula used for determining E.

I=Test period billing units from the rate application docket upon which the rates that are in effect are based. Absent extraordinary circumstances a public utility shall use demand billing units. This information is usually available in Statement BG of the rate application and/or settlement or compliance documents.

K=Required rate reduction per billing demand unit.

This formula may be broken down into the following four-step process:

$$(1) \quad A \times \frac{B}{C} = D$$

$$(2) \quad D \times \frac{E}{F} = G$$

$$(3) \quad D - G = H$$

$$(4) \quad \frac{H}{I} = K$$

Where

A=Income taxes allowable (exclusive of deferred tax make-up provisions, *i.e.* "South Georgia" provisions, and investment tax credit amortizations) included in the revenue requirement of the public utility's rate application docket upon which the rates in effect on the date the Federal corporate income tax rate change becomes effective were finally accepted or approved. This information is generally included in Statement BK or BL of the filing as revised after any summary dispositions where revised rates were required to be filed.

B=Revenue level in effect on the date the change in Federal corporate income tax rate becomes effective using test period billing determinants. This information is generally available from Statement BG of the rate application and/or settlement or compliance filing documents.

C=Revenue requirement from the rate application docket which includes A. This is generally included in Statement BK or BL of the filing.

G=Income taxes allowable at the new Federal corporate income tax rate.

H=Difference between income taxes allowable at the new Federal corporate income tax rate, and at the old Federal corporate income tax rate. This is the revenue reduction required to reflect the reduction in the Federal corporate income tax rate.

The Commission will use the data provided by a public utility in the rate application supporting its current rates on file to determine the reduction in rates to reflect the change in the Federal corporate tax rate. Since a public utility's rates generally differ, depending on the type of service the utility provides (firm transmission service, full requirements service, or partial requirements service) and for each customer group, the utility must make a separate rate reduction calculation for each type of service and each customer group.

In the first step of the formula, the income tax allowable component (A) from a public utility's last rate application is multiplied by the ratio of: (B) The test period revenues from the rates actually in effect on July 1, 1987 (using billing determinants from Statement BG of the public utility's rate application) to (C) the test period revenue requirement reported by the public utility in its last rate application (Statement BK or BL of the public utility's rate application). The result (D) represents the income tax allowable component which, for purposes of this rule, the Commission is presuming is included in a public utility's rate in effect on the date that the change in Federal corporate income tax rate became effective. This figure is based on the old Federal corporate income tax rate. The calculation recognizes that the public utility's current rate level may be designed to achieve test period revenues lower than the revenue requirement originally supported by the public utility in its rate application. The difference between generated rate levels and revenue requirement may be due to a variety of reasons including reductions in rate levels due to settlement agreements, voluntary reductions, Commission orders, and Commission opinions. For those rates that were determined by Commission opinion or equivalent order following a litigated proceeding, the income tax allowance from the company's finally accepted compliance filing, exclusive of deferred tax make-up provisions and investment tax credit amortizations, must be used as (D) in the formula instead of using "A X (B/C)" as (D). For settlement rates where the utility submitted a cost of service supporting the settlement rate level, the utility must use the income tax allowable figure contained in the settlement as (D) in the formula.

In the second step, the income tax allowable component (D) is multiplied by the ratio of: (E) The income tax factor at the new Federal corporate income tax rate to (F) the income tax factor at the old Federal corporate income tax rate. The result (G) represents the income tax allowable based on the new Federal corporate income tax rate.

In the third step of the formula, the income tax allowable component based on the new Federal corporate income tax rate (G) is subtracted from the income tax allowable component based on the old Federal corporate income tax rate (D). The result (H) represents the revenue reduction necessary to reflect the new corporate income tax rate.

Finally, in the fourth step of the formula, the revenue reduction figure (H) is divided by the demand billing units reported in the public utility's last rate application to determine the revenue reduction per unit of billing demand (K). Some adjustments in the implementation of this aspect of the formula may be allowed if, for example, the utility's rate is entirely energy-based, *i.e.*, on a per-kilowatt-hour basis, or if the utility's rate design incorporates unusual features.

In applying this formula, a utility may, by affidavit setting forth the reason, deviate from the use of demand billing units under extraordinary circumstances. Under this filing procedure intervenors may challenge this variation. The utility shall have the burden of proof in showing that a deviation from the use of demand billing units is based on extraordinary circumstances.

In order to expedite filings under this rule, a utility must provide the following in support of its rate reduction:

(A) Computations showing the application of each step of the formula methodology;

(B) Supporting workpapers including (1) all intermediate calculations necessary under the formula with narrative explanation where appropriate and (2) details on the derivation of all formula inputs together with copies of all statements and workpapers used as source documents;

(C) Detailed explanations of all adjustments to data shown on supporting statements (*e.g.*, adjustments to exclude South Georgia provisions from Federal Income Tax Allowable);

(D) Form of notice noting that the rates are to be effective as of July 1, 1987;

(E) Revised rate sheets reflecting the proposed rate reduction for every rate schedule to which the reduction is proposed;

(F) A list of any customers or services for which no reduction is proposed and the reasons for not reducing these rates.

A number of commenters raised issues regarding application of the formula. The Commission proposed to base the formula reduction on data derived from a utility's most recent rate filing. However, several commenters argued that the Commission should not rely on data in a utility's last rate filing since the data may have been filed several years ago and may no longer reflect a utility's true costs, and a formula based on the data would therefore not be valid. n21 n 21 *See, e.g.*, Idaho Power Company, Public Service Company of New Mexico, Utah Power and Light Company.

While a utility's specific costs may have changed since its last rate application, the data contained in this application are the most comprehensive on file at the Commission. A utility that believes that the data supporting its current rates no longer reflect its true costs should file an application for a general rate change.

The Iowa Public Service Company suggested that the Commission use data from a utility's most recent FERC annual report. The Commission disagrees since rates currently being collected are based on a utility's last cost-of-service filing and not annual report figures. Furthermore, it may not be possible to derive accurate data such as a utility's income tax allowable figure from its annual report.

In the formula, a utility's deferred tax make-up provision is excluded from the income taxes allowable component. These make-up provisions are designed to recover any deficiencies or to eliminate any excesses in the deferred tax reserves of a utility. Several commenters questioned whether the provision should be excluded in computing the appropriate reduction. n22 The Commission will consider any corrections to a utility's make-up provision amortization in conjunction with the utility's next full rate change application. The Commission believes that potentially complex questions involving any such adjustments should be dealt with in individual FPA section 205 or 206 proceedings, where all parties may question the necessary adjustment. Until that time, a utility should continue to accrue the deferred tax amortization amount in accordance with its previously approved plan of recovery.

n 22 *See, e.g.*, Allegheny Electric Cooperative, Inc., Coast Electric Power Association, *et al.*

Similarly, some commenters requested that the Commission establish a method of returning any overaccruals of a utility's unfunded future tax liability to the ratepayers. n23 The Commission is delaying consideration of any of these excess accruals until a utility's next rate application for the same reasons discussed above with regard to deferred tax make-up provisions. Utilities are required to establish a plan to return any excess accruals in rate applications. Until the next full rate change application a utility would not receive a windfall because any excess funds the utility collects for deferred income taxes are used as a rate base deduction until ultimately returned to the customers. n24

n 23 *See, e.g.,* Wholesale Distribution Customers, Arkansas Public Service Commission, Indiana Utility Consumer Counselor.

n 24 *See* Order No. 144, *46 FR 26613* (May 14, 1981), FERC Stats. & Reg. [Regulations Preambles 1977-1981] para. 61,254 (May 6, 1981); Order No. 144-A, *47 FR 8329* (Feb. 26, 1982) and *477 FR 8991* (Mar. 2, 1981), FERC Stats. & Regs. [Regulations Preambles (1982-1985] para. 30,340 (Feb. 22, 1982).

Under the formula, reductions were to be made on a per billing demand unit basis unless there were "extraordinary circumstances" not to do so. The NORP requested comments as to the appropriate circumstances under which exceptions to the use of demand billing units should be allowed. Although two commenters addressed this issue, neither provided the Commission with specific examples of what would constitute an extraordinary circumstance. n25 Therefore, the Commission will consider these situations on a case-by-case basis. Intervenors may challenge such a deviation. A utility shall have the burden of proof in showing that a variation from the use of demand billing units is based on extraordinary circumstances.

n 25 *See* Pacific Gas & Electric Company, Iowa Public Service Company.

E. Rates Affected

In the NOPR, the Commission proposed to exclude three types of utilities from the abbreviated filing procedure: A utility with rate filings pending before the Commission in which the tax component could be changed and in which the effective date of the rates at issue was no later than July 1, 1987; a utility that tendered rate applications to allow an effective date no later than July 1, 1987; or a utility whose rates already reflected the change in the Federal tax rate.

Some commenters suggested that formula reductions were unwarranted with respect to certain types of rates, specifically wheeling rates n26 and market-based rates. n27 Since the Commission is adopting only the formula rate reduction method, only rates which can be reduced by this method are included in this rule. These are requirements service rates (full or partial) and firm wheeling rates.

n 26 *See* Niagara Mohawk Power Corporation.
n 27 *See* Illinois Power Company.

Several commenters argued that a formula reduction was not appropriate for settlement rates, since the income tax allowable component in these rates may not be readily determinable. 2 n8 The formula assumes, in settlement rates, a *pro-rata* reduction in all of a utility's costs. For example, if a utility proposed revenues of $100 but settled for $75, all of the cost components submitted in support of the rate request to achieve those revenues, including income taxes allowable, would be reduced by 25 percent. The American Electric Power Service Corporation suggested a revision in the formula which would attribute the difference between the rate as filed and the settlement rate solely to a reduction in the rate of return on equity. Since it may be impossible to accurately allocate the reduction among all the different costs in a settlement rate, the Commission believes the best generic approach is to assume a *pro-rata* reduction in all the costs rather than attributing the reduction to a single factor. A utility that believes that application of the formula would result in inequitable treatment is encouraged to file an application under FPA section 205.

n 2 8 *See, e.g.,* Detroit Edison Company, Pennsylvania Power & Light Company, Edison Electric Institute.

Other commenters questioned whether the formula could be applied to settlement rates subject to moratorium provisions. For moratoriums that prohibit any rate change (increase or decrease), the Commission is adopting a procedure suggested by the Florida Power & Light Company. Adjustment to this type of rate can be made under the abbreviated procedure, but the Commission will defer the effective date of the reduction until after the moratorium term. However, if a moratorium prohibits only rate increases, the rate can be adjusted using the formula since filing for a rate decrease would not violate the moratorium.

Two commenters stated that a formula reduction in phase-in rates may not be appropriate. 2 n9 Phase-in rates present unique problems since rates are not computed using a conventional cost-of-service. Consequently, the Commission will adjust these rates on a case-by-case basis.

n 2 9 *See* Union Electric Company, Missouri Public Service Commission.

F. Effective Date of Decreased Rates

The Commission proposed that, in order to use the abbreviated filing procedure, a utility would have to file by June 1 1987, so that the proposed rates would become effective July 1, 1987, when the 34 percent tax rate becomes effective.

In this final rule, the Commission is establishing a filing timetable that utilities must use. Rates under this abbreviated filing are to be effective July 1, 1987, regardless of when the rate application is filed. To implement this procedure, the Commission is waiving any notice requirements in order to make July 1 the effective date of the new rate. 3 n0

n 3 0 *See* 18 CFR 35.11 (1987).

If a utility uses the abbreviated filing procedure, it must refund to its customers the difference between the rate unadjusted for the tax change and the new rate that reflects the tax adjustment. In order to encourage utilities to use this procedure, the Commission is not requiring that refunds be made with interest.

The Commission expects that many public utilities will file for rate reductions under this rule. In order to process these applications expeditiously, the Commission is establishing the following filing schedule which utilities must follow. The expiration of each of these filing periods will provide the Commission with an orderly and efficient basis to initiate its section 206 review of those utilities that do not file under this rule.

Schedule for Filings

First letter of utility name	Filing period

Schedule for Filings

First letter of utility name	Filing period
A-B	No later than September 15, 1987.
C-E	No later than September 30, 1987.
F-L	No later than October 15, 1987.
M-N	No later than October 31, 1987.
O-S	No later than November 15, 1987.
T-Z	No later than November 30, 1987.

Some commenters suggested that the Commission delay the effective date of the new rates until January 1, 1988. 3 n1 While this would be administratively simpler, the Commission is unwilling to do so since it would allow utilities to overcollect during the last six months of 1987. They further argued that the June 1 filing date proposed in the NOPR did not allow utilities sufficient time to collect the data necessary to file. The first filing period in the schedule established in the final rule gives utilities at least two months to collect this data. The Commission believes that this is sufficient time for a utility to prepare its filing.

n 3 1 *See, e.g.,* Florida Power & Light Company, Idaho Power Company.

G. Tax Rate for 1987

Since the Tax Reform Act reduced the tax rate to 34 percent effective July 1, 1987, the NOPR proposed that rate filings under the abbreviated procedure were to reflect this 34 percent tax rate.

Numerous commenters argued that if a utility were to use a split tax rate of 46 percent for the first half of 1987 and 34 percent for the remaining half, it would be violating standard accounting practices and Internal Revenue Service normalization requirements. 3 n2 They specifically cited *section 15 of the Internal Revenue Code* 3 n3 that required a blended tax rate of 40 percent for 1987. Therefore, they suggested that the Commission also use the 40 percent tax rate to determine the appropriate rate reductions.

n 3 2 *See, e.g.,* Deloitte, Haskins & Sells, Arthur Anderson & Company, Kentucky Utilities Company, Utah Power & Light Company, Commonwealth Edison, Southern California Edison Company.

n 3 3 *I.R.C. 15(a)* (1986) provides in part:

In any rate of tax imposed by this chapter changes, and if the taxable year includes the effective date of the change (unless that date is the first day of the taxable year), then

(1) Tentative taxes shall be computed by applying the rate for the period before the effective date of the change, and the rate for the period and after such date, to the taxable income for the entire taxable year; and

(2) The tax for such taxable year shall be the sum of that proportion of each tentative tax which the number of days in each period bears to the number of days in the entire taxable year.

Although the commenters are correct that income tax returns filed for the calendar year 1987 will be required to reflect the use of a blended rate, it does not necessarily follow that the blended rate is appropriate for the Commission to use for rate-making purposes. By using the split rate approach in which tax rates are assumed to change on July 1, 1987, from 46 percent to 34 percent the Commission has avoided the need to make two rate adjustments to give recognition to the tax rate change, one to reflect the blended rate of approximately 40 percent rate for calendar year taxpayers on January 1, 1987, and a second on January 1, 1988, to reflect the 34 percent rate. The split rate approach also avoids having to use a blended rate that would differ from the 40 percent rate for a utility that may have a tax year other than a calendar year. The Commission is not convinced that any distortions that may be caused by seasonal revenue patterns of a particular utility should outweigh the benefits that will be derived from the generic use of a single tax rate change date. Additionally, the Commission fails to understand those comments where concern was expressed that the use of a split rate would violate the normalization requirements of the Internal Revenue Code. The normalization requirements are annual ones that relate to certain differences between depreciation expenses on property claimed for tax purposes and that used for ratemaking and regulatory accounting purposes. The required annual normalization for property that is in service at the beginning of the year would, therefore, be provided through either one-half of the year at 46 percent and the other half at 34 percent of a full year at 40 percent since the total amount for the year under either approach would be the same. Straight line depreciation, which is used almost universally for ratemaking purposes, is simply not dependent upon seasonal patterns of revenues. 3 n4

n 3 4 The Commission confronted this blended rate issue in *West Texas Utilities. 37 FERC para. 61,284 (1986).* In that order the Commission directed the utility to use a split tax rate approach for 1987. On rehearing, *38 FERC para. 61,138 (1987),* the Commission allowed the use of the blended rate because the company's filing provided for rates at the 40 percent tax rate for 1987 and open-ended rates reflecting the 34 percent tax rate beginning in 1988. This rule is addressing utilities that have already been collecting at the 46 percent tax rate for the first six months of 1987.

H. Interventions

In the NOPR the Commission proposed that if any issue not directly related to the application of the formula were raised by an intervenor in the abbreviated proceeding it would be severed and automatically accorded complaint status under FPA section 206. The Central Vermont Public Service Corporation suggested that, as an inducement for utilities to file, the Commission should dismiss these issues without prejudice and require the intervenor to file the section 206 complaint separately. The Commission is adopting this suggestion. Dismissal of ancillary issues will allow utilities to make the abbreviated filing without automatically triggering FPA section 206 complaints.

I. Miscellaneous Issues

11Several utility commenters suggested that the proposed rule was unnecessary because the Commission's current regulations already provide for voluntary rate reductions or Commission-initiated section 206 investigations. 3 n5 They further suggested that the abbreviated filing procedure required too much documentation.

n 3 5 *See* Electric Utilities, Cincinnati Gas & Electric Company.

The Commission is promulgating this rule to encourage utilities to file for rate reductions. The formula established is easy to use and should provide accurate results. Furthermore, the scope of the Commission's review will be limited, and issues not relating to the formula will be dismissed without prejudice.

The Commission is adopting a suggestion of the Consumers Power Company to reduce the filing requirements. The Commission proposed to require utilities to file billing determinants for each of the 12 months immediately before and each of the 12 months immediately after the proposed effective date of the rate change. Billing determinants are a measure of the demand each customer group places on a utility. Instead, in this rule, the Commission is requiring utilities to file billing determinants only from the most recent 12 months available. The Commission has determined that future billing determinants are not needed to evaluate the applications tendered pursuant to this rule.

Several commenters urged the Commission to make the abbreviated filing procedure mandatory. 3 n6 The Commission has no statutory authority to require utilities to make rate reductions under FPA section 205. 3 n7 The Commission does intend, however, to initiate FPA section 206 proceedings against utilities that it believes are overcollecting as a result of the reduction of the tax rate.

n 3 6 *See, e.g.,* Coast Electric Power Association, *et al.,* Allegheny Electric Cooperative, Inc., Borough of Madison, New Jersey.

n 3 7 Rate filings under Section 205 of the Federal Power Act are at the discretion of the utility.

Several commenters suggested that the Commission waive filing fees under the abbreviated procedure. 3 n8 The Commission is adopting this suggestion and is waiving filing fees to encourage the use of this voluntary procedure.

n 3 8 *See, e.g.,* Cincinnati Gas & Electric Company, Florida Power & Light Company.

Otter Tail Power Company suggested that the rule should exempt utilities with minimal FERC revenues from the filing requirements. Since the abbreviated filing procedure is voluntary, creating such an exemption is unneccessary.

Although commenters urged the Commission to initiate procedures to determine the effects of the tax rate change on oil pipelines as well as electric utilities, this suggestion is outside the scope of this rulemaking. 3 n9 For the present, the Commission will continue to deal with oil pipeline rates on a case-by-case basis.

n 3 9 *See* Air Transport Association of America, Robert Abrams, Attorney General of New York.

The Florida Power & Light Company suggested that the Commission establish a single formula to account for any future changes in the Federal income tax rate. The Commission declines to adopt the suggestion. If Congress changes the Federal corporate income tax rate in the future, the Commission will evaluate the change at that time.

The Central Illinois Public Service Company suggested that the Commission not take any action on the rates of a utility until the jurisdictional state commission has had an opportunity to adjust retail rates to reflect the Tax Reform Act. The Commission also declines to adopt this suggestion. The Commission has a statutory obligation to ensure that electric wholesale rates are just and reasonable. If it were to wait for states to act first, it would be abdicating that responsibility.

III. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) 4 n0 generally requires a description and analysis of final rules that will have a significant economic impact on a substantial number of small entities. 4 n1 Specifically, if an agency promulgates a final rule under the Administrative Procedure Act (APA) 4 n2, a final RFA analysis must contain (1) a statement of the need for and objectives of the rule, (2) a summary of the issues raised by the public comments in response to any initial regulatory flexibility analysis, and the agency response to those comments, and (3) a description of significant alternatives to the rule consistent with the state objectives of the applicable statute that the agency considered and ultimately rejected. An agency is not required to make an RFA analysis, however, if it certifies that a rule will not have "a significant economic impact on a substantial number of small entities." 4 n3

n 4 0 *5 U.S.C. 601*-612 (1982).

n 4 *1 Id. 604(a).*

n 4 *2 Id. at 553.*

n 4 *3 Id. 605(b).*

In the proposed rule the Commission certified that the rule would not have a significant impact on a substantial number of small entities. In addition, the rule is voluntary and will be beneficial to public utilities by providing an expedited filing mechanism which they might use to reflect the reduction in the Federal corporate income tax rate. Accordingly, the Commission certifies that this rule will not have a "significant economic impact on a substantial number of small entities."

IV. Paperwork Reduction Act

The Paperwork Reduction Act, *44 U.S.C. 3501*-3520 (1982) and the Office of Management and Budget's (OMB) regulations, 5 CFR Part 1320 (1987), require that OMB approve certain information collection requirements imposed by agency rules. On June 8, 1987, the information collection provisions in this final rule were approved by OMB and assigned Control Number 1902-0096.

V. Effective Date

The Administrative Procedure Act permits an agency to make a substantive rule effective prior to 30 days after its publication in the Federal Register if the rulemaking relieves a restriction or if the agency finds good cause to waive the notice period and publishes this finding as part of the rule. 4 n4

n 4 4 *5 U.S.C. 553*(d) (1982).

The required finding of good cause for waiver of the 30-day notice period with respect to this rule is based upon the fact that the filing procedure adopted in this rule is voluntary. By making the rule effective immdiately, the Commission is allowing utilities which have already compiled the necessary data to make immediate filings. This will enable Commission staff to expedite rate reductions to customers. In addition, since the Commission is also relieving a restriction on its normal filing requirements for rate decrease filings, the Commission finds good cause to make the rule effective upon issuance.

List of Subjects

18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

5318 CFR Part 389

Reporting and recordkeeping requirements.

In consideration of the foregoing, the Commission amends Parts 35 and 389, Title 18, Chapter I, Code of Federal Regulations as set forth below.

By the Commission.

Kenneth F. Plumb,
Secretary.

PART 35 -- FILING OF RATE SCHEDULES

1. The authority citation for Part 35 is revised to read as follows:

Authority: Department of Energy Organization Act, *42 U.S.C. 7101*-7352 (1982); E.O. No. 12009, 3 CFR 1978 Comp., p. 142; Independent Offices Appropriations Act, *31 U.S.C. 9701* (1982); Federal Power Act, *16 U.S.C. 791a*-825r (1982); Public Utility Regulatory Policies Act, *16 U.S.C. 2601*-2645 (1982).

2. In § 35.13, paragraph (a)(2)(ii) is revised to read as follows:

§ 35.13 Filing of changes in rate schedules.

* * * * *

(a) *General rule.* * * *

(2) *Abbreviated filing requirements.* * * *

(ii) *For rate schedule changes other than rate increases.* (A) Except as provided in paragraph (a)(2)(ii)(B) of this section, any utility that files a rate schedule change that does not provide for a rate increase or that provides for a rate increase that is based solely on change in delivery points, a change in delivery voltage, or a similar change in service, must submit with its filing only the information required in paragraphs (b) and (c) of this section.

(B) Any utility that files a rate schedule change that provides for a rate decrease under § 35.27 of this part must submit with its filing only the information required by § 35.27 of this part.

* * * * *

3. Section 35.27 is added to read as follows:

§ 35.27 Changes of rates relating to changes in the Federal corporate income tax rate.

(a) *Purpose.* The abbreviated filing procedure and formula for this section are intended to permit a public utility to make an adjustment to its rates to reflect the decrease in the Federal corporate income tax rate pursuant to the Tax Reform Act of 1986. This abbreviated filing procedure and formula would be used by a public utility in lieu of a more comprehensive rate filing under § 35.13 of this part concerning changes in rate schedules.

(b) *Applicability.* (1) Except as provided in paragraph (b)(2), and (b)(3) of this section, a public utility may use the abbreviated filing procedure and formula in this section to adjust its rates to reflect the decrease in the Federal corporate income tax rate.

(2) If a public utility has a rate case currently pending before the Commission in which the change in the Federal corporate income tax rate can be reflected, the public utility may not use this section to adjust its rates.

(3) If a public utility has a rate accepted for filing by the Commission that provides for the automatic adjustment of its rates to reflect, without prior hearing, increases or decreases in the Federal corporate income tax rate, it may not use this section to adjust its rates.

(c) *Formula for rate adjustment to reflect changes in Federal corporate income tax rate.* (1) For purposes of establishing a rate reduction designed to reflect a percentage decrease in the Federal corporate income tax rate, a public utility must use the following formula:

$$K = \frac{D-D(E/F)}{I}$$

where:

D=Income taxes allowable included in rates in effect on the date that the change in Federal corporate income tax rate becomes effective.

E=Composite income tax factor using the new Federal corporate income tax rate and the effective state income tax rate from the rate application docket upon which existing rates are based. This is computed by the following formula:

$$\frac{\text{composite marginal income tax rate}}{\text{1-composite marginal income tax rate}}$$

F=Composite income tax factor using the old Federal corporate income tax rate. This is computed by the same formula used for determining E.

I=Test period billing units from rate application docket upon which the rates that are in effect are based. Absent extraordinary circumstances a public utility must use demand billing units. This information is usually available in Statement BG of the rate application and/or settlement or compliance documents.

K=Required rate reduction per billing demand unit.

(2) A separate rate calculation using this formula is required for each type of service a public utility provides and for each individual customer group thereunder.

(d) *Abbreviated filing requirements for rate schedule changes due to reductions in the Federal corporate income tax rate.* Any public utility that files a rate schedule change providing for a rate decrease that is based on a change in the

Federal corporate income tax rate must submit with its finding only the information required in paragraphs (d)(1) and (d)(2) of this section.

(1) *General information.* Any public utility filing under this section must file the following general information:

(i) A list of documents submitted with the rate schedule change;

(ii) The date on which the public utility proposes to make the rate schedule effective;

(iii) The names and addresses of persons to whom a copy of the rate schedule change has been mailed;

(iv) A brief description of the rate schedule change;

(v) A statement of the reasons for the rate schedule change;

(vi) A showing that all requisite agreement to the rate schedule change, or to the filing of the rate schedule change, including any agreement required by contract, has in fact been obtained;

(vii) Computations showing the application of each step of the formula methodology;

(viii) Supporting workpapers including all intermediate calculations necessary under the formula with narrative explanation where appropriate, and details on the derivation of all formula inputs together with copies of all statements and workpapers used as source documents;

(ix) Detailed explanations of all adjustments to data shown on supporting statements (*e.g.,* adjustments to exclude South Georgia provisions from Federal income taxes allowable);

(x) Form of notice stating that the rates are to be effective July 1, 1987;

(xi) Revised rate sheets reflecting the proposed rate reduction for every rate schedule to which the reduction is proposed;

(xii) A list of any customers or services for which no reduction is proposed and the reasons for not reducing these rates; and

(xiii) A form of notice suitable for publication in the Federal Register in accordance with § 35.8 of this part.

(2) *Information relating to the effect of the rate schedule change.* Any public utility filing under paragraph (d)(1) of this section must also file the following information or materials:

(i) A table or statement comparing sales and services and revenues from sales and services under the rate schedule to be superseded or supplemented and under the rate schedule change, by applying the components of each such rate schedule to the billing determinants for each class of service, for each customer, and for each delivery point or set of delivery points that constitute a billing unit:

(A) For each of the twelve most recent available months prior to the effective date of the rate schedule change; and

(B)(*1*) If in the immediately preceding rate change filing the public utility filed Statements BG and BH under paragraph (h) of § 35.13 of this part for Period I, for each of the twelve months of Period I; and

(*2*) If in the immediately preceding rate change filing Period II is the test period, for each of the twelve months of Period II.

(ii) A comparison of the rate schedule change and the public utility's other rates for similar wholesale services.

(e) *Hearing issues.* (1) The only issues that may be raised by Commission staff or any intervenor under the procedures established in this section are:

(i) Whether or not the public utility may file under this section,

(ii) Whether or not the formula in § 35.27 has been properly applied, and

(iii) Whether or not the correct information was used in that formula.

(2) Any other issue raised will be severed from the proceeding and dismissed without prejudice.

(f) *Effective date.* Rates proposed under the filing are to have a July 1, 1987 effective date. A public utility that chooses to use the abbreviated filing procedure and formula contained in this section must make its filing according to the following schedule:

Schedule for Filings

First letter of utility name	Filing period
A-B	No later than September 15, 1987.
C-E	No later than September 30, 1987.
F-L	No later than October 15, 1987.
M-N	No later than October 31, 1987.
O-S	No later than November 15, 1987.
T-Z	No later than November 30, 1987.

(g) *Refunds.* A utility filing under this procedure must refund to its customers the difference between the rates unadjusted for the tax change and the new rate that reflects the tax adjustment. These refunds will be made without interest.

(h) *Waiver of filing fees.* Any filing under this section may be filed without the filing fee required by § 35.0 of this part.

PART 389 -- OMB CONTROL NUMBERS FOR COMMISSION INFORMATION COLLECTION REQUIREMENTS

4. The authority citation for Part 389 continues to read as follows:

Authority: Paperwork Reduction Act of 1980 *(44 U.S.C. 3501*-3520) (1982).

§ 389.101 [Amended]

5. The table of OMB Control Numbers in § 389.101(b) is amended by inserting "35.27" in numerical order in the section column and "0096" in the corresponding position in the OMB Control Number column.

Appendix A

Note: This appendix will not appear in the *Code of Federal Regulations.*

1. Arthur Young

2. Public Service Company of Oklahoma

3. Cities and Villages of Algoma, *et al.*

4. American Electric Power Service Corporation

5. Air Transport Association of America

6. Borough of Madison, New Jersey

7. Cincinnati Gas & Electric Company

8. Public Service Company of New Mexico

9. Illinois Power Company

10. Philadelphia Electric Company

11. Consumers Power Company

12. Missouri Public Service Commission

13. Arkansas Public Service Commission

14. Utah Power & Light Company

15. Allegheny Electric Cooperative, Inc.

16. Mississippi Power Company

17. New England Power Company

18. Union Electric Company

19. American Public Power Association

20. Wholesale Distribution Customers

21. Public Systems

22. Niagara Mohawk Power Corporation

23. Iowa Power & Light Company

24. Department of Water Resources of the State of California

25. Kentucky Utilities Company

26. Pacific Gas & Electric Company

27. Central Illinois Public Service Company

28. Carolina Power & Light Company

29. Pennsylvania Power & Light Company

30. Saffer Utility Consultants, Inc.

31. Detroit Edison Company

32. Southwestern Electric Power Company

33. Florida Power & Light Company

34. Idaho Power Company

35. Robert Abrams, Attorney General of New York

36. Public Service Electric & Gas Company

37. Electric Utilities

38. Golden Spread Electric Cooperative, Inc., *et al.*

39. Central Vermont Public Service Corporation

40. Coast Electric Power Association, *et al.*

41. Colorado Public Utilities Commission

42. Deloitte, Haskins & Sells

43. Edison Electric Institute

44. Public Service Company of Colorado

45. Arthur Andersen & Company

46. Arizona Public Service Company

47. Iowa Public Service Company

48. Indiana Utility Consumer Counselor

49. Otter Tail Power Company

50. Commonwealth Edison Company

51. Sierra Pacific Power Company

52. Southern California Edison Company

[FR Doc. 87-15090 Filed 7-1-87; 8:45 am]

BILLING CODE 6717-01-M

Line	Description	% of Capital	Cost of Capital	Rate of Return		Amount	Notes
1	**Cost of Capital Per Docket DE 16-384 Settlment Agreement**						
2	Common Stock Equity	50.97%	9.50%	4.84%			
3	Preferred Stock Equity	0.13%	6.00%	0.01%			
4	Long Term Debt	48.80%	7.15%	3.49%			
5	Short Term Debt	0.11%	1.54%	0.00%			
6	Total	100.00%		8.34%			
7	**Cost of Service**						
8	Proforma Income Taxes				$	5,125,436	Per Docket DE 16-384 Settlment Agreement Revenue Requirement
9	**Revenue Reduction Per FERC Formula = D - D*(E/F)**						
10	D (Composite Income Taxes)				$	5,125,436	Line 8
11	E (New Effective Tax Rate Factor)					0.3744	= 1 / (1 - new tax rate) - 1
12	F (Old Effective Tax Rate Factor)					0.6559	= 1 / (1 - old tax rate) - 1
13	**Revenue Reduction**				$	2,199,753	Line 10 - Line 10 * Line 11 ÷ Line 12
14	**Revenue Reduction Due to 2017 Step Adjustment**						
15	As Settled Revenue Requirement for 2017 Step Adjustment				$	900,194	See Schedule DLC-4 Page 1
16	Revenue Requirement for 2017 Step Adjustment Adjusted For Tax Change					855,203	See Schedule DLC-4 Page 2
17	**Revenue Reduction**				$	44,991	Line 15 - Line 16
18	**Grand Total Revenue Reduction Due to Lower Tax Rates**				$	2,244,744	Line 13 + Line 17

May 1, 2017 Step Adjustment

Line No.	Description	5/1/2017 Investment Year 2016
	Rate Effective Date	5/1/2017
	Utility Plant:	
1	Beginning Utility Plant [(1)]	$ 283,122,968
2	Plant Additions [(2)]	13,666,114
3	Retirements	(2,345,862)
4	Ending Utility Plant	294,443,220
5	Beginning Accumulated Depreciation	98,980,036
6	Depreciation	10,260,907
7	Retirements	(2,340,795)
8	Cost of Removal and Salvage	(725,971)
9	Ending Accumulated Depreciation	106,174,178
10	Ending Net Utility Plant	$ 188,269,043
	Revenue Requirement:	
11	Change in Net Plant	$ 4,126,111
12	80% of Change in Net Plant	3,300,889
13	Pre-Tax Rate of Return	11.52%
14	Return and Taxes	380,134
15	Depreciation Expense on 80% of Plant Additions [(3)]	415,422
16	Property Taxes on 80% Change in Net Plant [(4)]	104,638
17	Revenue Requirement	$ 900,194
18	**Revenue Cap:**	
19	May 1, 2017, 2018 & 2019 Step Adjustment Revenue Requirement Cap	$ 4,500,000
20	Less: May 1, 2017 Step Adjustment Revenue Requirement	900,194
21	Remaining May 1, 2018 & 2019 Step Adjustment Revenue Requirement Cap	$ 3,599,806

Notes:
(1) Beginning Utility Plant from page 2, plus Kingston substation of $10,336,281
(2) Plant Additions from page 2, less Kingston substation of $10,336,281
(3) See page 4
(4) 3.17% rate (2016 Property Taxes of $5,971,944 / 2016 Net Utility Plant of $188,269,043)

May 1, 2017 Step Adjustment (Adjusted for TCJA)

Line No.	Description	Rate Effective Date 5/1/2017 Investment Year 2016
	Utility Plant:	
1	Beginning Utility Plant [1]	$ 283,122,968
2	Plant Additions [2]	13,666,114
3	Retirements	(2,345,862)
4	Ending Utility Plant	294,443,220
5	Beginning Accumulated Depreciation	98,980,036
6	Depreciation	10,260,907
7	Retirements	(2,340,795)
8	Cost of Removal and Salvage	(725,971)
9	Ending Accumulated Depreciation	106,174,178
10	Ending Net Utility Plant	$ 188,269,043
	Revenue Requirement:	
11	Change in Net Plant	$ 4,126,111
12	80% of Change in Net Plant	3,300,889
13	Pre-Tax Rate of Return	10.15%
14	Return and Taxes	335,143
15	Depreciation Expense on 80% of Plant Additions [3]	415,422
16	Property Taxes on 80% Change in Net Plant [4]	104,638
17	Revenue Requirement	$ 855,203
18	Revenue Cap:	
19	May 1, 2017, 2018 & 2019 Step Adjustment Revenue Requirement Cap	$ 4,500,000
20	Less: May 1, 2017 Step Adjustment Revenue Requirement	855,203
21	Remaining May 1, 2018 & 2019 Step Adjustment Revenue Requirement Cap	$ 3,644,797

Notes:
(1) Beginning Utility Plant from page 2, plus Kingston substation of $10,336,281
(2) Plant Additions from page 2, less Kingston substation of $10,336,281
(3) See page 4
(4) 3.17% rate (2016 Property Taxes of $5,971,944 / 2016 Net Utility Plant of $188,269,043)

2016 Gross Plant Detail

Description	Beginning Balance	Additions	Retirements	Ending Balance
301-00 Organization-E	380	-	-	380
303-00 Intangible Software-5 Yea-E	3,958,942	92,040	-	4,050,981
303-01 Intangible Software-3 Yea-E	87,196	-	-	87,196
303-02 Intangible Software-10 Yea-E	2,307,249	-	-	2,307,249
343-00 Prime Movers-E	56,575	-	-	56,575
353-00 Transmission Station Equi-E	34,220	(34,220)	-	-
360-01 ROW - Distribution-E	991,116	-	-	991,116
360-02 ROW - Distribution-E	1,674,812	-	-	1,674,812
361-00 Distribution Structures-E	167,773	-	-	167,773
362-00 Distribution Station Equi-E	23,696,229	12,947,587	(180,145)	36,463,670
364-00 Distribution Poles, Tower-E	54,781,196	2,794,857	(348,903)	57,227,150
365-00 Distribution Overhead Con-E	71,213,961	3,065,702	(701,357)	73,578,306
366-00 Distribution Underground -E	1,841,623	35,257	(6,337)	1,870,543
367-00 Distribution Underground -E	18,242,829	818,757	(88,835)	18,972,752
368-00 Distribution Line Transfo-E	24,590,384	820,798	(298,373)	25,112,809
368-01 Transformer Installations-E	18,572,941	912,800	(42,638)	19,443,103
369-00 Distribution Services-E	20,341,811	982,496	(253,675)	21,070,632
370-00 Distribution Meters-E	9,636,392	385,812	(61,974)	9,960,229
370-01 Meter Installation-E	4,027,591	508,276	(16,358)	4,519,509
371-00 Installations on Customer-E	1,886,935	297,589	(129,864)	2,054,660
373-00 Street Lights & Signal Sy-E	3,237,653	178,950	(137,473)	3,279,130
373-01 Street Lights & Signal Sy-E	-	-	-	-
389-00 General & Misc. Land-E	18,620	-	-	18,620
390-00 Structures-E	3,787,332	26,053	(3,908)	3,809,477
390-01 General & Misc. Structure-E	-	-	-	-
391-01 Office Furniture & Fixtur-E	267,375	4,296	-	271,671
391-03 Computer Equipment-E	-	-	-	-
392-00 Transportation Equipment-E	1,078,761	-	(5,067)	1,073,695
393-00 Stores Equipment-E	79,908	-	-	79,908
394-00 Tools, Shop and garage Eq-E	1,539,171	79,463	(2,858)	1,615,777
395-00 Laboratory Equipment-E	792,711	30,751	-	823,462
397-00 Communication Equipment-E	3,772,058	55,130	(68,098)	3,759,091
398-00 Miscellaneous Equipment-E	102,943	-	-	102,943
399-00 Other Intangible Plant-E	-	-	-	-
Grand Total	272,786,687	24,002,395	(2,345,862)	294,443,220

2016 Accumulated Depreciation Detail

Description	Beginning Balance	Provision	Retirements	Cost of Removal	Salvage	Ending Balance
301-00 Organization	-	-	-	-	-	-
303-00 Intangible Software-5 Year	3,273,350	304,704	-	-	-	3,578,054
303-01 Intangible Software-3 Year	87,196	-	-	-	-	87,196
303-02 Intangible Software-10 Year	721,991	230,725	-	-	-	952,715
343-00 Prime Movers	17,747	3,955	-	-	-	21,702
350-01 ROW - Transmission	-	-	-	-	-	-
350-02 ROW ¿ Transmission	-	-	-	-	-	-
352-00 Transmission Structures	-	-	-	-	-	-
353-00 Transmission Station Equipme	-	-	-	-	-	-
354-00 Transmission Towers & Fixtur	-	-	-	-	-	-
355-00 Transmission Poles & Fixture	-	-	-	-	-	-
356-00 Transmission Overhead Conduc	-	-	-	-	-	-
360-01 ROW - Distribution	-	-	-	-	-	-
360-02 ROW ¿ Distribution	-	-	-	-	-	-
361-00 Distribution Structures	143,327	(7,007)	-	-	-	136,320
362-00 Distribution Station Equipme	7,364,421	988,538	(180,145)	(36,398)	385	8,136,801
364-00 Distribution Poles, Towers &	22,341,062	507,501	(348,903)	(256,752)	4,862	22,247,770
365-00 Distribution Overhead Conduc	22,691,293	694,550	(701,357)	(318,438)	15,453	22,381,501
366-00 Distribution Underground Con	587,417	10,316	(6,337)	(465)	0	590,932
367-00 Distribution Underground Con	6,939,941	(1,243,333)	(88,835)	(16,627)	8,084	5,599,232
368-00 Distribution Line Transforme	8,931,881	1,186,352	(298,373)	(111,182)	-	9,708,678
368-01 Transformer Installations	3,997,430	904,602	(42,638)	(621)	-	4,858,773
368-02 Transformers Installations	-	-	-	-	-	-
369-00 Distribution Services	13,235,456	1,441,734	(253,675)	(13,597)	138	14,410,056
370-00 Distribution Meters	2,066,303	1,979,406	(61,974)	-	-	3,983,736
370-01 Meter Installation	(2,077,150)	2,774,788	(16,358)	-	-	681,280
370-02 Meter Installations	-	-	-	-	-	-
371-00 Installations on Customers P	363,888	218,398	(129,864)	(14,109)	10,368	448,681
373-00 Street Lights & Signal Syste	1,881,836	520,889	(137,473)	(16,746)	24,549	2,273,055
373-01 Street Lights & Signal Syste	-	-	-	-	-	-
389-00 General & Misc. Land	-	-	-	-	-	-
390-00 Structures	1,803,802	(284,858)	(3,908)	-	-	1,515,037
390-01 General & Misc. Structures	863	-	-	-	-	863
391-01 Office Furniture & Fixtures	(525,150)	386,757	-	-	-	(138,394)
391-03 Computer Equipment	518	3,828	-	-	-	4,346
392-00 Transportation Equipment	1,048,135	(2,991)	-	-	-	1,045,145
393-00 Stores Equipment	58,463	(3,051)	-	-	-	55,412
394-00 Tools, Shop and garage Equip	672,614	24,824	(2,858)	-	-	694,581
395-00 Laboratory Equipment	297,321	65,228	-	-	-	362,549
397-00 Communication Equipment	2,978,647	(450,925)	(68,098)	(4,877)	-	2,454,746
398-00 Miscellaneous Equipment	77,433	5,978	-	-	-	83,411
399-00 Other Tangible Property	-	-	-	-	-	-
Grand Total	98,980,036	10,260,907	(2,340,795)	(789,812)	63,841	106,174,178

2016 Depreciation by FERC Account

Description	Additions	Less: Kingston	Net Additions	Depreciation Rate	Annual Depreciation
303-00 Intangible Software-5 Yea-E	92,040	-	92,040	20.00%	18,408
353-00 Transmission Station Equi-E	(34,220)	-	(34,220)	N/A	N/A
362-00 Distribution Station Equi-E	12,947,587	10,336,281	2,611,306	2.60%	67,894
364-00 Distribution Poles, Tower-E	2,794,857	-	2,794,857	3.70%	103,410
365-00 Distribution Overhead Con-E	3,065,702	-	3,065,702	3.64%	111,592
366-00 Distribution Underground -E	35,257	-	35,257	2.04%	719
367-00 Distribution Underground -E	818,757	-	818,757	2.55%	20,878
368-00 Distribution Line Transfo-E	820,798	-	820,798	3.00%	24,624
368-01 Transformer Installations-E	912,800	-	912,800	2.89%	26,380
369-00 Distribution Services-E	982,496	-	982,496	5.67%	55,708
370-00 Distribution Meters-E	385,812	-	385,812	5.00%	19,291
370-01 Meter Installation-E	508,276	-	508,276	5.00%	25,414
371-00 Installations on Customer-E	297,589	-	297,589	7.56%	22,498
373-00 Street Lights & Signal Sy-E	178,950	-	178,950	7.79%	13,940
390-00 Structures-E	26,053	-	26,053	2.08%	542
391-01 Office Furniture & Fixtur-E	4,296	-	4,296	5.83%	250
394-00 Tools, Shop and garage Eq-E	79,463	-	79,463	3.64%	2,892
395-00 Laboratory Equipment-E	30,751	-	30,751	3.90%	1,199
397-00 Communication Equipment-E	55,130	-	55,130	6.60%	3,639
Grand Total	24,002,395	10,336,281	13,666,114	3.80%	519,277

Pre-Tax Rate of Return
December 31, 2015 Pro Forma

Line No.	Description	Proformed Amount	Weight	Cost of Capital	Weighted Cost of Capital	Tax Factor	Pre-Tax Cost
1	Common Stock Equity	$ 77,284,950	50.97%	9.50%	4.84%	1.3744	6.65%
2	Preferred Stock Equity	189,800	0.13%	6.00%	0.01%		0.01%
3	Long Term Debt	74,000,000	48.80%	7.15%	3.49%		3.49%
4	Short Term Debt	161,783	0.11%	1.54%	0.00%		0.00%
5	Total	$ 151,636,533	100.00%		8.34%		10.15%

Notes:
(1) New tax factor calculated using a Federal Tax Rate of 21% and State Tax Rate of 7.9% (effective tax rate of 27.241%)

Line No.	Date	2015 Test Year Units		Regulatory Liability
1	Jan-18	107,718,250	$	(199,143)
2	Feb-18	106,475,729	$	(196,846)
3	Mar-18	110,811,143	$	(204,861)
4	Apr-18	91,139,375	$	(168,493)
5	May-18	85,892,926	$	(158,794)
6	Jun-18	102,495,562	$	(189,487)
7	Jul-18	106,755,260	$	(197,363)
8	Aug-18	118,052,728	$	(218,249)
9	Sep-18	114,610,029	$	(211,884)
10	Oct-18	89,853,566	$	(166,116)
11	Nov-18	86,512,214	$	(159,938)
12	Dec-18	93,886,299	$	(173,571)
13		1,214,203,082	**$**	**(2,244,744)**

UNITIL ENERGY SYSTEMS, INC.
Wind Storm (October 2017) Incremental Cost - Recovery
Calculation of Increment to the Storm Recovery Adjustment Factor
Effective May 1, 2018

Description		Amount
Incremental Annual Recovery (Page 2)	$	284,569
Sales (kWh) - 12 months ending December 31, 2017		1,188,641,108
Storm Recovery Adjustment Factor (Increment, $/kWh)*	$	0.00023

* To be added to the current Storm Recovery Adjustment Factor.

Current SRAF (effective February 2018)	$	0.00139
less: recovery of Hurricane Sandy (terminates effective 5/1/2018)	$	(0.00043)
plus: recovery of Wind Storm (proposed for effect 5/1/2018)	$	0.00023
Total SRAF for effect May 1, 2018:	$	0.00119

UNITIL ENERGY SYSTEMS, INC.
Wind Storm (October 2017) - Recovery Schedule

	Year (A)	Beginning Balance With Interest (B)	Annual Recovery (C)	Ending Balance (D)	Balance Subject to Interest (E)	Interest Rate (F)	Interest (G)	Cumulative Interest (H)
(1)	May 2018 - April 2019	$ 1,257,109	$ 284,569	$ 972,540	$ 1,114,825	5.20%	$ 57,971	$ 57,971
(2)	May 2019 - April 2020	$ 1,030,511	$ 284,569	$ 745,942	$ 888,227	5.20%	$ 46,188	$ 104,159
(3)	May 2020 - April 2021	$ 792,130	$ 284,569	$ 507,561	$ 649,846	5.20%	$ 33,792	$ 137,951
(4)	May 2021 - April 2022	$ 541,353	$ 284,569	$ 256,784	$ 399,069	5.20%	$ 20,752	$ 158,702
(5)	May 2022 - April 2023	$ 277,536	$ 284,569	$ (7,033)	$ 135,251	5.20%	$ 7,033	$ 165,735
	Total Recovery		$ 1,422,844				$ 165,735	

Column Notes

(A)	Time period
(B)	Prior period Column (D) + Prior period Column (G)
(C)	Annual Recovery
(D)	Column (B) - Column (C)
(E)	(Column (B) + Column (D)) ÷ 2
(F)	UES's Cost of Debt net of deferred taxes
(G)	Column (E) times Column (F)
(H)	Prior Year Column (H) + Current Year Column (G)

UNITIL ENERGY SYSTEMS, INC.
Wind Storm (October 2017) Incremental Costs

	Month (A)	Beginning Balance (B)	Wind Storm Charges (C)	Ending Balance (D)	Balance Subject to Interest (E)	Interest Rate (F)	Interest (G)	Balance (H)
(1)	Dec-17	$0	$1,233,742	$1,233,742	$616,871	4.27%	$2,237	$1,235,979
(2)	Jan - Apr 2018	$1,235,979	$0	$1,235,979	$1,235,979	5.20%	$21,130	$1,257,109
			$1,233,742				$23,367	$1,257,109

Unitil Energy Systems, Inc.

PUC 308.11 - F-1 Rate of Return

12 Months Ending December 31, 2017

Schedule 1: Calculation of Per Books Rate of Return

Cost of Service	Rolling 12 Months
Electric Service Revenue	$ 141,089,478
Other Operating Revenue	1,264,226
Total Operating Revenue	**142,353,704**
Operating Expenses:	
Purchased Power	47,455,276
Transmission	30,292,992
Distribution	9,125,967
Cust. Accounting & Service	6,486,237
Admin. & General	9,992,153
Depreciation	10,589,917
Amortization	3,883,955
Taxes-Other Than Income	6,306,184
State & Federal Income Taxes - Adjusted	4,820,791
Int on Customer Deposits	59,340
Total Operating Expenses	**129,012,814**
Net Operating Income	**$ 13,340,891**
Less: Flow-Through Oper. Inc. (Exc. Lost Base Rev.)	688,898
Net Operating Income - Adjusted	**$ 12,651,993**

Rate Base	Period End
Utility Plant in Service	$ 324,214,118
Less: Reserve for Depreciation & Amortization	114,418,513
Net Utility Plant	**209,795,605**
Plus:	
M&S Inventories	1,557,600
Cash Working Capital	2,908,994
Prepayments	4,543,701
Less:	
Deferred Income Taxes	35,144,165
Regulatory Liabilities	16,270,286
Customer Advances	566,074
Customer Deposits	801,216
Total Rate Base	**$ 166,024,158**
Utility Operating Income - Current Cost of Capital	$ 13,879,620
Utility Operating Income - Adjusted	$ 12,651,993
Operating Income Deficiency (Surplus)	**$ 1,227,627**
Income Tax Gross-Up	$ 798,561
Revenue Deficiency (Surplus)	**$ 2,026,188**
Return on Rate Base - Actual	**7.62%**
Return on Rate Base - Current Cost of Capital	**8.36%**
ROE - Actual	**8.09%**
ROE - Authorized DE 16-384	**9.50%**

Schedule 2: Current Cost of Capital	**Amount Outstanding**	**Percent Total**	**Cost Rate**	**Weighted Cost Rate**
Common Equity	$ 80,739,631	52.62%	9.50%	**5.00%**
Preferred Stock Equity	$ 189,300	0.12%	6.00%	**0.01%**
Long Term Debt	$ 72,500,000	47.25%	7.10%	**3.35%**
Short Term Debt (a)	$ -	0.00%	2.31%	**0.00%**
Total	**$ 153,428,931**	**100.00%**		**8.36%**

(a) Excluding Accrued Revenue, Power Supply Working Capital and CWIP

UNITIL ENERGY SYSTEMS, INC. SCHEDULE 3
SALES BY CUSTOMER CLASS

DEFINITIONS:
Small (or Commercial) Customers = Regular General Service Schedule G2 customers, whether industrial or commercial , with average use consistently below two-hundred (200) kilovolt-amperes of demand and generaly less than one-hundred (100,000) kilowatt-hours per month
Large (or Industrial) Customers = Large General Service Schedule G1 customers, whether industrial or commercial , with average use consistently equal to or in excess of two-hundred (200) kilovolt-amperes of demand and generally greater than or equal to one-hundred (100,000) kilowatt-hours per month

Year to Date - December 31, 2017

Line No.	Title of Account (a)	OPERATING REVENUES Year to Date Annual (b)	OPERATING REVENUES Amount for Previous Year (c)	MEGAWATT HOURS SOLD Year to Date Annual (d)	MEGAWATT HOURS SOLD Amount for Previous Year (e)	AVERAGE NUMBER OF CUSTOMERS PER MONTH Current Year (f)	AVERAGE NUMBER OF CUSTOMERS PER MONTH Previous Year (g)
1	Sales of Electricity						
2	(440) Residential Sales	$76,250,052	$70,537,609	484,341	483,687	66,168	65,781
3	(442) Commercial and Industrial Sales						
4	Small (or Commercial)	39,423,464	35,284,845	326,499	306,594	10,386	10,034
5	Large (or Industrial)	19,079,903	15,381,093	319,634	282,684	143	130
6	(444) Public Street and Highway Lighting	2,380,242	2,236,472	8,073	8,117	1,641	1,692
7	(445) Other Sales to Public Authorities	3,108,305	6,341,361	50,094	106,943	384	765
8	(446) Sales to Railroads and Railways	0	0	0	0	0	0
9	(448) Interdepartmental Sales	0	0	0	0	0	0
10	TOTAL Sales to Ultimate Consumers	140,241,966	129,781,380	1,188,641	1,188,025	78,722	78,402
11	(447) Sales for Resale	847,512	492,891	21,885	15,379		
12	TOTAL Sales of Electricity	$141,089,478	$130,274,271	1,210,526	1,203,404	78,722	78,402
13	Sales of Electricity						

Quarter to Date - December 31, 2017

Line No.	Title of Account (a)	OPERATING REVENUES Year to Date Quarter (b)	OPERATING REVENUES Amount for Previous Year (c)	MEGAWATT HOURS SOLD Year to Date Quarterly (d)	MEGAWATT HOURS SOLD Amount for Previous Year (e)	AVERAGE NUMBER OF CUSTOMERS PER MONTH Current Quarter (f)	AVERAGE NUMBER OF CUSTOMERS PER MONTH Previous Year (g)
1	Sales of Electricity						
2	(440) Residential Sales	$20,442,598	$15,604,085	113,344	107,090	65,512	65,882
3	(442) Commercial and Industrial Sales						
4	Small (or Commercial)	11,065,984	8,066,702	82,643	67,696	10,676	10,010
5	Large (or Industrial)	5,887,222	3,786,838	87,040	63,866	156	129
6	(444) Public Street and Highway Lighting	665,445	557,178	2,028	1,889	1,595	1,684
7	(445) Other Sales to Public Authorities	75,530	1,573,204	10	24,730	5	762
8	(446) Sales to Railroads and Railways	0	0	0	0	0	0
9	(448) Interdepartmental Sales	0	0	0	0	0	0
10	TOTAL Sales to Ultimate Consumers	38,136,779	29,588,007	285,065	265,271	77,944	78,467
11	(447) Sales for Resale	268,405	123,864	4,478	2,661	0	0
12	TOTAL Sales of Electricity	$38,405,184	$29,711,871	289,543	267,932	77,944	78,467
13	Sales of Electricity						

Unitil Energy Systems, Inc.
Rate Design Calculation
Individual Rate Design Calculations

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Test Year 2015 Billing Units	Step 1 Adjustment Rates	Step 2 Adjustment Rates	Step 2 Adjustment Revenue May 1, 2018	Percent Change	Tax Adjusted Rates	Tax Adjusted Revenue May 1, 2018	Percent Change
Residential - D								
Test Year Consumers	785,306	$15.24	$16.12	$12,661,259	5.79%	$16.12	$12,661,259	0.00%
All kWh	497,875,828	$0.03566	$0.03773	$18,783,423	5.79%	$0.03537	$17,609,495	-6.25%
Total Design Revenue				$31,444,681	5.79%		$30,270,754	-3.73%
Small General Service - G2 kWh								
Test Year Consumers	5,238	$17.27	$18.27	$95,717	5.79%	$18.27	$95,717	0.00%
Annual kWh	607,397	$0.01440	$0.01523	$9,251	5.79%	$0.00878	$5,332	-42.36%
Total Design Revenue				$104,968	5.79%		$101,050	-3.73%
Small General Service - G2 QR WH /SH								
Test Year Consumers	3,454	$9.14	$9.67	$33,411	5.79%	$9.67	$33,411	0.00%
Annual kWh	5,742,223	$0.03149	$0.03331	$191,271	5.79%	$0.03185	$182,883	-4.39%
Total Design Revenue				$224,682	5.79%		$216,294	-3.73%
Small General Service - G2 Demand								
Test Year Consumers	123,180	$27.43	$29.02	$3,574,789	5.79%	$29.02	$3,574,789	0.00%
Demand kW	1,348,556	$10.35	$10.95	$14,770,315	5.79%	$10.45	$14,086,374	-4.63%
Annual kWh	347,811,789	$0.00000	$0.00000	$0	0.00%	$0.00000	$0	0.00%
Total Design Revenue				$18,345,104	5.79%		$17,661,162	-3.73%
G2 Demand - kW Transformer Ownership Discount								
Test Year kW	50,269	($0.50)	($0.50)	-$25,134		($0.50)	-$25,134	
Total Design Revenue				-$25,134	0.00%		-$25,134	0.00%
Subtotal G2 Demand inc. Transformer Ownership Discount								
Total Design Revenue				$18,319,969	5.80%		$17,636,028	-3.73%
Large General Service - G1								
Test Year Consumers Secondary	1,497	$152.40	$161.23	$241,357	5.79%	$161.23	$241,357	
Test Year Consumers Primary	381	$81.28	$85.99	$32,761	5.79%	$85.99	$32,761	
Demand kVA	1,022,850	$7.42	$7.85	$8,025,672	5.79%	$7.55	$7,723,570	
Annual kWh	353,924,392	$0.00000	$0.00000	$0	0.00%	$0.00000	$0	
Total Design Revenue				$8,299,790	5.79%		$7,997,688	-3.64%
G1 - kVA Transformer Ownership Discount								
Test Year kVA	415,470	($0.50)	($0.50)	-$207,735		($0.50)	-$207,735	
Total Design Revenue				-$207,735	0.00%		-$207,735	0.00%
Subtotal G1 inc. Transformer Ownership Discount								
Total Design Revenue				$8,092,055	5.95%		$7,789,953	-3.73%

Unitil Energy Systems, Inc.
Rate Design Calculation
Individual Rate Design Calculations

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Test Year 2015 Billing Units	**Step 1 Adjustment Rates**	**Step 2 Adjustment Rates**	**Step 2 Adjustment Revenue May 1, 2018**	**Percent Change**	**Tax Adjusted Rates**	**Tax Adjusted Revenue May 1, 2018**	**Percent Change**
Outdoor Lighting - OL								
Delivery charge - Annual kWh	8,241,454	$0.00000	$0.00000	$0		$0.00000	$0	
Fixture revenue								
100W Mercury Vapor Street	17,494	$12.96	$13.72	$239,930		$13.20	$230,973	
175W Mercury Vapor Street	894	$15.37	$16.26	$14,542		$15.66	$13,999	
250W Mercury Vapor Street	945	$17.42	$18.43	$17,421		$17.75	$16,771	
400W Mercury Vapor Street	1,940	$20.75	$21.95	$42,583		$21.13	$40,994	
1000W Mercury Vapor Street	24	$41.19	$43.57	$1,046		$41.95	$1,007	
250W Mercury Vapor Flood	850	$18.56	$19.64	$16,685		$18.90	$16,062	
400W Mercury Vapor Flood	1,403	$22.21	$23.50	$32,971		$22.62	$31,740	
1000W Mercury Vapor Flood	272	$36.80	$38.93	$10,596		$37.48	$10,200	
100W Mercury Vapor Power Bracket	4,860	$13.09	$13.84	$67,285		$13.33	$64,773	
175W Mercury Vapor Power Bracket	715	$14.52	$15.36	$10,983		$14.79	$10,573	
50W Sodium Vapor Street	41,383	$13.20	$13.96	$577,798		$13.44	$556,227	
100W Sodium Vapor Street	1,182	$14.85	$15.71	$18,573		$15.13	$17,879	
150W Sodium Vapor Street	4,221	$14.92	$15.78	$66,607		$15.19	$64,121	
250W Sodium Vapor Street	13,250	$18.68	$19.77	$261,901		$19.03	$252,123	
400W Sodium Vapor Street	3,106	$23.55	$24.91	$77,397		$23.98	$74,508	
1000W Sodium Vapor Street	1,728	$40.67	$43.03	$74,351		$41.42	$71,575	
150W Sodium Vapor Flood	2,796	$17.19	$18.19	$50,845		$17.51	$48,947	
250W Sodium Vapor Flood	3,708	$20.27	$21.44	$79,517		$20.64	$76,549	
400W Sodium Vapor Flood	4,724	$23.02	$24.36	$115,051		$23.45	$110,756	
1000W Sodium Vapor Flood	2,789	$41.03	$43.40	$121,051		$41.78	$116,532	
50W Sodium Vapor Power Bracket	1,304	$12.21	$12.92	$16,852		$12.44	$16,222	
100W Sodium Vapor Power Bracket	777	$13.71	$14.50	$11,264		$13.96	$10,844	
175W Metal Halide Street	19	$19.44	$20.56	$389		$19.79	$374	
250W Metal Halide Street	0	$21.13	$22.36	$0		$21.52	$0	
400W Metal Halide Street	0	$21.92	$23.18	$0		$22.32	$0	
175W Metal Halide Flood	0	$22.45	$23.75	$0		$22.87	$0	
250W Metal Halide Flood	0	$24.24	$25.65	$0		$24.69	$0	
400W Metal Halide Flood	0	$24.28	$25.69	$0		$24.73	$0	
1000W Metal Halide Flood	465	$31.46	$33.28	$15,460		$32.03	$14,882	
175W Metal Halide Power Bracket	0	$18.19	$19.24	$0		$18.52	$0	
250W Metal Halide Power Bracket	0	$19.34	$20.45	$0		$19.69	$0	
400W Metal Halide Power Bracket	0	$20.67	$21.86	$0		$21.05	$0	
42W 3600 K LED Area Light Fixture	0	$12.85	$13.59	$0		$13.08	$0	
57W 5200K LED Area Light Fixture	0	$12.89	$13.64	$0		$13.13	$0	
25W 3000K LED Cobra Head Fixture	0	$12.80	$13.54	$0		$13.03	$0	
88W 8300K LED Cobra Head Fixture	0	$12.98	$13.73	$0		$13.22	$0	
108W 11500K LED Cobra Head Fixture	0	$13.04	$13.80	$0		$13.28	$0	
193W 21000K LED Cobra Head Fixture	0	$13.29	$14.06	$0		$13.54	$0	
123W 12180K LED Flood Light Fixture	0	$13.09	$13.84	$0		$13.33	$0	
194W 25700K LED Flood Light Fixture	0	$13.30	$14.07	$0		$13.54	$0	
297W 38100K LED Flood Light Fixture	0	$13.60	$14.39	$0		$13.85	$0	
Total Design Revenue				$1,941,099	5.79%		$1,868,631	-3.73%
Total Design Revenue				$60,127,454			$57,882,710	

Unitil Energy Systems, Inc.
Rate Design Calculation
Individual Rate Design Calculations

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Test Year 2015 Billing Units	Step 1 Adjustment Rates	Step 2 Adjustment Rates	Step 2 Adjustment Revenue May 1, 2018	Percent Change	Tax Adjusted Rates	Tax Adjusted Revenue May 1, 2018	Percent Change
Total Billed kWh	1,214,203,082							
Total Billed kW/kVA	2,371,406							
Step Adjustment $ (does not include recoupment)				$3,302,989				
Step Adjustment Percentage Change (not including transformer discounts)				5.79%				
Step Adjustment Percentage Change Total				5.81%				
Recoupment $		$1,411,065		-$1,411,065				
Recoupment $/kWh		$0.00116		-$0.00116				
Tax Adjustment $							-$2,244,744	
Tax Adjustment Percentage Change (not including customer charges and transformer discounts)							-5.13%	
Tax Adjustment Percentage Change Total							-3.73%	
Cumulative $ Adjustments on May 1, 2018				$1,891,924			-$352,820	

Unitil Energy Systems, Inc.
Typical Bill Impacts - December 1, 2017 vs. May 1, 2018
Impacts do NOT include the Electricity Consumption Tax
Impact on D Rate Customers

Average kWh	Total Bill Using Rates 12/1/2017	Total Bill Using Rates 5/1/2018	Total Difference	% Total Difference
125	$36.35	$37.03	$0.68	1.9%
150	$40.58	$41.21	$0.64	1.6%
200	$49.02	$49.57	$0.55	1.1%
250	$57.47	$57.94	$0.47	0.8%
300	$65.91	$66.30	$0.39	0.6%
350	$74.36	$74.66	$0.30	0.4%
400	$82.80	$83.03	$0.22	0.3%
450	$91.25	$91.39	$0.14	0.2%
500	$99.70	$99.75	$0.06	0.1%
525	$103.92	$103.93	$0.02	0.0%
550	$108.14	$108.12	($0.03)	(0.0%)
575	$112.36	$112.30	($0.07)	(0.1%)
600	$116.59	$116.48	($0.11)	(0.1%)
625	$120.81	$120.66	($0.15)	(0.1%)
650	$125.03	$124.84	($0.19)	(0.2%)
675	$129.25	$129.02	($0.23)	(0.2%)
700	$133.48	$133.20	($0.27)	(0.2%)
725	$137.70	$137.39	($0.31)	(0.2%)
750	$141.92	$141.57	($0.36)	(0.3%)
775	$146.15	$145.75	($0.40)	(0.3%)
825	$154.59	$154.11	($0.48)	(0.3%)
925	$171.48	$170.84	($0.64)	(0.4%)
1,000	$184.15	$183.38	($0.77)	(0.4%)
1,250	$226.38	$225.20	($1.18)	(0.5%)
1,500	$268.61	$267.01	($1.59)	(0.6%)
2,000	$353.06	$350.64	($2.42)	(0.7%)
3,500	$606.43	$601.53	($4.89)	(0.8%)
5,000	$859.79	$852.42	($7.37)	(0.9%)

	Rates - Effective December 1, 2017	Rates - Proposed May 1, 2018	Difference
Customer Charge	**$15.24**	**$16.12**	**$0.88**
	kWh	kWh	kWh
Distribution Charge:	$0.03682	$0.03537	($0.00145)
External Delivery Charge	$0.02637	$0.02637	$0.00000
Stranded Cost Charge	($0.00057)	($0.00057)	$0.00000
Storm Recovery Adjustment Factor	$0.00139	$0.00119	($0.00020)
System Benefits Charge	$0.00456	$0.00456	$0.00000
Default Service Charge	$0.10034	$0.10034	$0.00000
TOTAL	**$0.16891**	**$0.16726**	**($0.00165)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - December 1, 2017 vs. May 1, 2018
Impacts do NOT include the Electricity Consumption Tax
Impact on G2 Rate Customers

Load Factor	Average Monthly kW	Average Monthly kWh	Total Bill Using Rates 12/1/2017	Total Bill Using Rates 5/1/2018	Total Difference	% Total Difference
20%	5	730	$171.47	$172.55	$1.08	0.6%
20%	10	1,460	$315.51	$316.07	$0.56	0.2%
20%	15	2,190	$459.55	$459.60	$0.05	0.0%
20%	25	3,650	$747.64	$746.65	($0.99)	(0.1%)
20%	50	7,300	$1,467.84	$1,464.28	($3.56)	(0.2%)
20%	75	10,950	$2,188.05	$2,181.91	($6.14)	(0.3%)
20%	100	14,600	$2,908.26	$2,899.55	($8.71)	(0.3%)
20%	150	21,900	$4,348.67	$4,334.81	($13.86)	(0.3%)
36%	5	1,314	$245.74	$246.03	$0.28	0.1%
36%	10	2,628	$464.06	$463.03	($1.03)	(0.2%)
36%	15	3,942	$682.37	$680.04	($2.34)	(0.3%)
36%	25	6,570	$1,119.00	$1,114.05	($4.96)	(0.4%)
36%	50	13,140	$2,210.58	$2,199.07	($11.50)	(0.5%)
36%	75	19,710	$3,302.15	$3,284.10	($18.05)	(0.5%)
36%	100	26,280	$4,393.72	$4,369.12	($24.60)	(0.6%)
36%	150	39,420	$6,576.87	$6,539.17	($37.69)	(0.6%)
50%	5	1,825	$310.73	$310.32	($0.41)	(0.1%)
50%	10	3,650	$594.04	$591.62	($2.42)	(0.4%)
50%	15	5,475	$877.34	$872.92	($4.42)	(0.5%)
50%	25	9,125	$1,443.95	$1,435.52	($8.43)	(0.6%)
50%	50	18,250	$2,860.47	$2,842.01	($18.45)	(0.6%)
50%	75	27,375	$4,276.98	$4,248.51	($28.47)	(0.7%)
50%	100	36,500	$5,693.50	$5,655.00	($38.50)	(0.7%)
50%	150	54,750	$8,526.54	$8,467.99	($58.54)	(0.7%)

	Rates - Effective December 1, 2017	Rates - Proposed May 1, 2018	Difference
Customer Charge	**$27.43**	**$29.02**	**$1.59**
	All kW	**All kW**	**All kW**
Distribution Charge	$10.35	$10.45	$0.10
Stranded Cost Charge	($0.11)	($0.11)	$0.00
TOTAL	**$10.24**	**$10.34**	**$0.10**
	kWh	**kWh**	**kWh**
Distribution Charge	$0.00116	$0.00000	($0.00116)
External Delivery Charge	$0.02637	$0.02637	$0.00000
Stranded Cost Charge	($0.00011)	($0.00011)	$0.00000
Storm Recovery Adj. Factor	$0.00139	$0.00119	($0.00020)
System Benefits Charge	$0.00456	$0.00456	$0.00000
Default Service Charge	$0.09381	$0.09381	$0.00000
TOTAL	**$0.12718**	**$0.12582**	**($0.00136)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - December 1, 2017 vs. May 1, 2018
Impacts do NOT include the Electricity Consumption Tax
Impact on G2 kWh Meter Rate Customers

Average Monthly kWh	Total Bill Using Rates 12/1/2017	Total Bill Using Rates 5/1/2018	Total Difference	% Total Difference
15	$19.39	$20.28	$0.90	4.6%
75	$27.85	$28.33	$0.48	1.7%
150	$38.44	$38.39	($0.04)	(0.1%)
250	$52.55	$51.81	($0.74)	(1.4%)
350	$66.66	$65.22	($1.44)	(2.2%)
450	$80.77	$78.63	($2.14)	(2.6%)
550	$94.89	$92.05	($2.84)	(3.0%)
650	$109.00	$105.46	($3.54)	(3.2%)
750	$123.11	$118.88	($4.23)	(3.4%)
900	$144.28	$139.00	($5.28)	(3.7%)

	Rates - Effective December 1, 2017	Rates - Proposed May 1, 2018	Difference
kWh Meter Customer Charge	$17.27	$18.27	$1.00
	All kWh	All kWh	All kWh
Distribution Charge	$0.01556	$0.00878	($0.00678)
External Delivery Charge	$0.02637	$0.02637	$0.00000
Stranded Cost Charge	($0.00057)	($0.00057)	$0.00000
Storm Recovery Adjustment Factor	$0.00139	$0.00119	($0.00020)
System Benefits Charge	$0.00456	$0.00456	$0.00000
Default Service Charge	$0.09381	$0.09381	$0.00000
TOTAL	**$0.14112**	**$0.13414**	**($0.00698)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - December 1, 2017 vs. May 1, 2018
Impacts do NOT include the Electricity Consumption Tax
Impact on G2 QRWH and SH Rate Customers

Average kWh	Total Bill Using Rates 12/1/2017	Total Bill Using Rates 5/1/2018	Total Difference	% Total Difference
100	$24.96	$25.39	$0.43	1.7%
200	$40.78	$41.12	$0.33	0.8%
300	$56.60	$56.84	$0.23	0.4%
400	$72.42	$72.56	$0.13	0.2%
500	$88.25	$88.28	$0.03	0.0%
750	$127.80	$127.58	($0.22)	(0.2%)
1,000	$167.35	$166.88	($0.47)	(0.3%)
1,500	$246.46	$245.49	($0.97)	(0.4%)
2,000	$325.56	$324.09	($1.47)	(0.5%)
2,500	$404.67	$402.70	($1.97)	(0.5%)

	Rates - Effective December 1, 2017	Rates - Proposed May 1, 2018	Difference
Customer Charge	**$9.14**	**$9.67**	**$0.53**
	All kWh	**All kWh**	**All kWh**
Distribution Charge	$0.03265	$0.03185	($0.00080)
External Delivery Charge	$0.02637	$0.02637	$0.00000
Stranded Cost Charge	($0.00057)	($0.00057)	$0.00000
Storm Recovery Adjustment Factor	$0.00139	$0.00119	($0.00020)
System Benefits Charge	$0.00456	$0.00456	$0.00000
Default Service Charge	$0.09381	$0.09381	$0.00000
TOTAL	**$0.15821**	**$0.15721**	**($0.00100)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - December 1, 2017 vs. May 1, 2018
Impacts do NOT include the Electricity Consumption Tax
Impact on G1 Rate Customers

Load Factor	Average Monthly kVa	Average Monthly kWh	Total Bill Using Rates 12/1/2017	Total Bill Using Rates 5/1/2018	Total Difference	% Total Difference
25.0%	200	36,500	$6,005.92	$5,991.31	($14.61)	(0.2%)
25.0%	400	73,000	$11,859.44	$11,821.40	($38.04)	(0.3%)
25.0%	600	109,500	$17,712.96	$17,651.48	($61.48)	(0.3%)
25.0%	800	146,000	$23,566.48	$23,481.57	($84.91)	(0.4%)
25.0%	1,000	182,500	$29,420.00	$29,311.66	($108.34)	(0.4%)
25.0%	1,500	273,750	$44,053.80	$43,886.87	($166.93)	(0.4%)
25.0%	2,000	365,000	$58,687.60	$58,462.09	($225.51)	(0.4%)
25.0%	2,500	456,250	$73,321.40	$73,037.30	($284.10)	(0.4%)
25.0%	3,000	547,500	$87,955.20	$87,612.51	($342.69)	(0.4%)
40.0%	200	58,400	$8,644.43	$8,600.04	($44.39)	(0.5%)
40.0%	400	116,800	$17,136.46	$17,038.85	($97.61)	(0.6%)
40.0%	600	175,200	$25,628.50	$25,477.67	($150.83)	(0.6%)
40.0%	800	233,600	$34,120.53	$33,916.48	($204.05)	(0.6%)
40.0%	1,000	292,000	$42,612.56	$42,355.30	($257.26)	(0.6%)
40.0%	1,500	438,000	$63,842.64	$63,452.33	($390.31)	(0.6%)
40.0%	2,000	584,000	$85,072.72	$84,549.37	($523.35)	(0.6%)
40.0%	2,500	730,000	$106,302.80	$105,646.40	($656.40)	(0.6%)
40.0%	3,000	876,000	$127,532.88	$126,743.43	($789.45)	(0.6%)
57.0%	200	83,220	$11,634.75	$11,556.60	($78.15)	(0.7%)
57.0%	400	166,440	$23,117.09	$22,951.97	($165.12)	(0.7%)
57.0%	600	249,660	$34,599.44	$34,347.34	($252.09)	(0.7%)
57.0%	800	332,880	$46,081.78	$45,742.72	($339.07)	(0.7%)
57.0%	1,000	416,100	$57,564.13	$57,138.09	($426.04)	(0.7%)
57.0%	1,500	624,150	$86,269.99	$85,626.52	($643.47)	(0.7%)
57.0%	2,000	832,200	$114,975.86	$114,114.95	($860.91)	(0.7%)
57.0%	2,500	1,040,250	$143,681.72	$142,603.38	($1,078.34)	(0.8%)
57.0%	3,000	1,248,300	$172,387.58	$171,091.81	($1,295.77)	(0.8%)
71.0%	200	103,660	$14,097.36	$13,991.41	($105.94)	(0.8%)
71.0%	400	207,320	$28,042.31	$27,821.60	($220.72)	(0.8%)
71.0%	600	310,980	$41,987.27	$41,651.78	($335.49)	(0.8%)
71.0%	800	414,640	$55,932.23	$55,481.97	($450.26)	(0.8%)
71.0%	1,000	518,300	$69,877.18	$69,312.15	($565.03)	(0.8%)
71.0%	1,500	777,450	$104,739.58	$103,887.61	($851.96)	(0.8%)
71.0%	2,000	1,036,600	$139,601.97	$138,463.08	($1,138.89)	(0.8%)
71.0%	2,500	1,295,750	$174,464.36	$173,038.54	($1,425.82)	(0.8%)
71.0%	3,000	1,554,900	$209,326.75	$207,614.00	($1,712.75)	(0.8%)

	Rates - Effective December 1, 2017	Rates - Proposed May 1, 2018	Difference
Customer Charge	**$152.40**	**$161.23**	**$8.83**
	All kVA	**All kVA**	**All kVA**
Distribution Charge	$7.42	$7.55	$0.13
Stranded Cost Charge	($0.14)	($0.14)	$0.00
TOTAL	**$7.28**	**$7.41**	**$0.13**
	All kWh	**All kWh**	**All kWh**
Distribution Charge	$0.00116	$0.00000	($0.00116)
External Delivery Charge	$0.02637	$0.02637	$0.00000
Stranded Cost Charge	($0.00014)	($0.00014)	$0.00000
Storm Recovery Adjustment Factor	$0.00139	$0.00119	($0.00020)
System Benefits Charge	$0.00456	$0.00456	$0.00000
Default Service Charge*	$0.08714	$0.08714	$0.00000
TOTAL	**$0.12048**	**$0.11912**	**($0.00136)**

* Default Service Charge for the G1 class is determined monthly. For purposes of this comparison, the March 2018 rate is unchanged.

Unitil Energy Systems, Inc.
Typical Bill Impacts - December 1, 2017 vs. May 1, 2018
Impacts do NOT include the Electricity Consumption Tax
Impact on OL Rate Customers *

	Nominal Watts	Lumens	Type	Average Monthly kWh	Total Bill Using Rates 12/1/2017	Total Bill Using Rates 5/1/2018	Total Difference	% Total Difference
	Mercury Vapor:							
1	100	3,500	ST	43	$18.41	$18.59	$0.18	1.0%
2	175	7,000	ST	71	$24.37	$24.56	$0.19	0.8%
3	250	11,000	ST	100	$30.09	$30.28	$0.19	0.6%
4	400	20,000	ST	157	$40.65	$40.81	$0.17	0.4%
5	1,000	60,000	ST	372	$88.33	$88.58	$0.25	0.3%
6	250	11,000	FL	100	$31.23	$31.44	$0.21	0.7%
7	400	20,000	FL	157	$42.11	$42.30	$0.20	0.5%
8	1,000	60,000	FL	380	$84.95	$85.11	$0.16	0.2%
9	100	3,500	PB	48	$19.17	$19.34	$0.17	0.9%
10	175	7,000	PB	71	$23.52	$23.69	$0.17	0.7%
	High Pressure Sodium:							
11	50	4,000	ST	23	$16.11	$16.32	$0.21	1.3%
12	100	9,500	ST	48	$20.93	$21.14	$0.21	1.0%
13	150	16,000	ST	65	$23.16	$23.34	$0.18	0.8%
14	250	30,000	ST	102	$31.61	$31.82	$0.21	0.7%
15	400	50,000	ST	161	$43.95	$44.17	$0.22	0.5%
16	1,000	140,000	ST	380	$88.82	$89.06	$0.23	0.3%
17	150	16,000	FL	65	$25.43	$25.66	$0.23	0.9%
18	250	30,000	FL	102	$33.20	$33.43	$0.23	0.7%
19	400	50,000	FL	161	$43.42	$43.63	$0.21	0.5%
20	1,000	140,000	FL	380	$89.18	$89.42	$0.24	0.3%
21	50	4,000	PB	23	$15.12	$15.32	$0.20	1.3%
22	100	95,000	PB	48	$19.79	$19.98	$0.18	0.9%
	Metal Halide:							
23	175	8,800	ST	74	$28.82	$29.07	$0.25	0.9%
24	250	13,500	ST	102	$34.06	$34.31	$0.25	0.7%
25	400	23,500	ST	158	$41.94	$42.13	$0.18	0.4%
26	175	8,800	FL	74	$31.83	$32.14	$0.32	1.0%
27	250	13,500	FL	102	$37.17	$37.48	$0.31	0.8%
28	400	23,500	FL	158	$44.30	$44.54	$0.23	0.5%
29	1,000	86,000	FL	374	$78.85	$78.92	$0.07	0.1%
30	175	8,800	PB	74	$27.57	$27.80	$0.23	0.8%
31	250	13,500	PB	102	$32.27	$32.48	$0.21	0.7%
32	400	23,500	PB	158	$40.69	$40.85	$0.16	0.4%

Luminaire Charges For Year Round Service:

Rates - Effective December 1, 2017

		Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.	
Customer Charge	$0.00	1	$12.96	11	$13.20	23	$19.44
		2	$15.37	12	$14.85	24	$21.13
	All kWh	3	$17.42	13	$14.92	25	$21.92
Distribution Charge	$0.00116	4	$20.75	14	$18.68	26	$22.45
External Delivery Charge	$0.02637	5	$41.19	15	$23.55	27	$24.24
Stranded Cost Charge	($0.00057)	6	$18.56	16	$40.67	28	$24.28
Storm Recovery Adj. Factor	$0.00139	7	$22.21	17	$17.19	29	$31.46
System Benefits Charge	$0.00456	8	$36.80	18	$20.27	30	$18.19
Default Service Charge	$0.09381	9	$13.09	19	$23.02	31	$19.34
		10	$14.52	20	$41.03	32	$20.67
TOTAL	**$0.12672**			21	$12.21		
				22	$13.71		

Rates - Proposed May 1, 2018

		Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.	
Customer Charge	$0.00	1	$13.20	11	$13.44	23	$19.79
		2	$15.66	12	$15.13	24	$21.52
	All kWh	3	$17.75	13	$15.19	25	$22.32
Distribution Charge	$0.00000	4	$21.13	14	$19.03	26	$22.87
External Delivery Charge	$0.02637	5	$41.95	15	$23.98	27	$24.69
Stranded Cost Charge	($0.00057)	6	$18.90	16	$41.42	28	$24.73
Storm Recovery Adj. Factor	$0.00119	7	$22.62	17	$17.51	29	$32.03
System Benefits Charge	$0.00456	8	$37.48	18	$20.64	30	$18.52
Default Service Charge	$0.09381	9	$13.33	19	$23.45	31	$19.69
		10	$14.79	20	$41.78	32	$21.05
TOTAL	**$0.12536**			21	$12.44		
				22	$13.96		

	Difference	Mercury Vapor-Difference		Sodium Vapor-Difference		Metal Halide-Difference	
Customer Charge	$0.00	1	$0.24	11	$0.24	23	$0.35
		2	$0.29	12	$0.28	24	$0.39
	All kWh	3	$0.33	13	$0.27	25	$0.40
Distribution Charge	($0.00116)	4	$0.38	14	$0.35	26	$0.42
External Delivery Charge	$0.00000	5	$0.76	15	$0.43	27	$0.45
Stranded Cost Charge	$0.00000	6	$0.34	16	$0.75	28	$0.45
Storm Recovery Adj. Factor	($0.00020)	7	$0.41	17	$0.32	29	$0.57
System Benefits Charge	$0.00000	8	$0.68	18	$0.37	30	$0.33
Default Service Charge	$0.00000	9	$0.24	19	$0.43	31	$0.35
		10	$0.27	20	$0.75	32	$0.38
TOTAL	**($0.00136)**			21	$0.23		
				22	$0.25		

* Luminaire charges based on All-Night Service option.

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

RICHARD L. FRANCAZIO

New Hampshire Public Utilities Commission

Docket --

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List of Attachments

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Richard L. Francazio and my business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities?

A. I am the Director of Business Continuity and Compliance for Unitil Service Corp. ("USC"), which provides centralized management and administrative services to Unitil Corporation's affiliates including Unitil Energy Systems, Inc. ("UES" or the "Company"). In this position, I am responsible for organizational readiness related to Business Continuity events, including storm conditions, and the development of policy and procedures that will ensure the Company's compliance with all applicable Federal, State and Local Regulation.

Q. Please describe your business and educational background.

A. I have over 40 years of experience in the utility industry with expertise in many aspects of the distribution and transmission energy delivery business. Prior to joining USC in March 2009, I was employed at National Grid for 27 years and prior to that, five years at Florida Power & Light ("FP&L"). After my stay at FP&L as a system protection engineer, I joined New England Electric System (now part of National Grid) as a Supervisor in the Substation Operation and

Maintenance department and over the years held a variety of senior management positions including Vice President of New England Electric Operations (included Rhode Island, Massachusetts and New Hampshire); Vice President of Construction Services for National Grid USA, and Vice President and Director of Emergency Planning for National Grid US.

From 1995 to 2009 I also served as National Grid's System Storm Director responsible for implementing and coordinating restoration activities across all of National Grid USA. I retired from National Grid in 2009 and joined USC in April of that year. I now act as Incident Commander during major storm events for the whole of Unitil. I have a Bachelor of Science degree in Electrical Engineering from Roger Williams College and a Masters of Business Administration from Boston University.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes. I testified before the Commission regarding UES's deployment of resources following the 2008 ice storm Docket DE 10-001 and in UES Docket 13-065. In addition, I have testified before the Massachusetts Department of Public Utilities ("MDPU") in a number of emergency response dockets.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the Company's proposal to increase the Storm Recovery Adjustment Factor ("SRAF") by incorporating the cost recovery for the October 30, 2017 wind storm. My testimony will describe the impact of the storm on the distribution infrastructure of UES, the Company's pre-planning, restoration and recovery efforts, the resulting costs of those efforts, and why the October event qualifies for major storm treatment as defined by the Commission.

Q. How is your testimony organized?

A. The remainder of my testimony consists of two segments. First, I will describe the impact of the October storm and the Company's response. Second, I will explain why the storm qualifies as a major event under the Commission's definition of a major storm event.

III. DESCRIPTION OF THE OCTOBER 30TH, 2017 WIND STORM

Q. When did the October storm strike New England and the UES service territory?

A. Beginning on October 26th (Thursday), weather forecasters began reporting a significant storm system they expected to impact the northeast late Sunday (October 29th) into Monday (October 30th) with heavy rain, lightning and gusty winds. Over the weekend, forecasters increased the severity and likelihood of the storm system, predicting moderate to heavy amounts of rain and frequent gusts between 35-50 mph with isolated gusts up to 60 mph. High wind watches and warnings were issued for nearly all portions of the northeast especially for coastal parts of RI, MA and NH. Following the storm's passage, nearly 1.4 million customers were without power in the northeast due to severe flash flooding and tree damage. In terms of New Hampshire, this storm was ranked the state's fourth most impactful event in realtion to customer outages, (at peak) affecting over 277,000.

Q. Please describe Unitil's preparations for the October 30, 2017 Wind Storm

A. In response to the forecasted winds, Unitil began holding daily, internal coordination conference calls beginning Friday (October 27th) with key internal personnel to coordinate preparation activities. Based on the forecasted weather and potential for outages, the Company began issuing its preparatory communication messages and initiating contact with life support customers, regulators, emergency response, and municipal officials the following day. The Regional Emergency Response Centers ("REOCs") were established prior to the storm to quickly take local control, if needed. The Seacoast and Capital REOCs were opened in advance of the weather event (Sunday evening) with the System Emergency Operations Center ("EOC") opening at 6:00 AM on Monday (October 30th) to provide essential logistical and communications support for responding resources.

SEOC Logistics began acquiring resources on Friday October 27th and continued the process throughout the weekend. By Monday October 30th, the Company had acquired the resources identified in Table 1 for UES. Unitil also participated in scheduled North Atlantic Mutual Assistance Group ("NAMAG") calls, which began on October 30th. The Company was compelled to request additional resources through NAMAG because of the storm's Northeast region wide impact; however, the NAMAG response to the Company's request was limited to an additional six (6) line crews capable of supporting its restoration in a timely manner. Ultimately, the Unitil-acquired contracted line resources were redirected to other impacted, regional utilities, as Company restoration progress was made sooner than the projected arrival time of the resources.

Table 1 - October 30, 2017 UES Crew Availability

Crew Type	# Crews	# FTEs (personnel)
Internal Line	12	24
External Line	55	110
Tree	15	30
Damage Assessor	9	9
Wires Down	18	18
Support	≈80	≈80

As the storm approached New Hampshire, the Company implemented its multi-layered communications protocols detailed within its Electric Emergency Response Plan ("ERP"). The Communication team crafted public service announcements ("PSAs") to distribute prior to and throughout the event, which provide important wires down safety messages, Company contact information and details on restoration progress. Messaging began on Saturday, October 28th and was updated twice daily throughout the event for a total of seven (7) PSAs being disseminated through various media channels (radio and print media). In addition, the Company leveraged its social media channels (Twitter/Facebook) to share additional information with customers via 50+ messages broadcast throughout the restoration effort.

Once storm-related outages began to occur at approximately 10:00 AM on October 29th, the Company issued Restoration Status Reports, which provided outage and crew information, every four (4) hours to regulators, municipal emergency response personnel and others until the conclusion of the event.

> Life Support customers were contacted by the Customer Service Center ("CSC") prior to the storm's impact and were provided safety and contact information in the event of a service interruption. Nearly 35,000 customer calls were made to the CSC throughout the restoration effort, which were in addition to online outage reporting.

> Communications with Regulatory, Elected, and State Management Officials also began on Saturday, October 28th, notifying them of Unitil's preparations and providing them points of contact. The Company also worked with the New Hampshire Homeland Security and Emergency Management ("NH HSEM") staff on securing waivers to expedite border crossing procedures for crews coming from Canada. The Company continued to update these contacts with routine information

including the required New Hampshire Public Utilities Commission ("NH PUC") Crew and Outage report forms until restoration was nearly completed.

The Municipal Rooms in each REOC were activated and staffed with liaisons to provide a 24/7 available contact for municipal first responders within their respective service territories. Pre-event notices were sent to all Municipal Official contacts, informing them of the time the Municipal Room would be open and the means to contact the Company. The Company also began hosting Municipal Conference calls to speak one-on-one with the affected town emergency response personnel to provide restoration and crew information and solicit any issues or concerns on Monday, October 30th.

Q. How many UES customers were impacted by the October storm?

Peak interruptions occurred at approximately 5:19 AM on October 30th with 33,354 customers impacted (43% of Unitil's New Hampshire customers) with a cumulative total of 53,332 customers being impacted throughout the storm event and subsequent restoration effort.

Q. When did the Company restore service to all customers?

A. The first outage occurred on October 29th at 7:50 PM and the last customer was restored at November 1st at 5:54 PM; however, the majority of impacted customers (95%) were restored by 6:00 AM on November 1st. There were some delayed responses due to the inability of crews to work during periods of high winds. The storm reported two distinct waves or peaks of high winds. I believe that the

Company's completion of its restoration effort in approximately 48 hours was a notable achievement.

Q. When did the Company release the contracted resources it had acquired in advance of the October 30, 2017 storm?

A. After restoring power to its New Hampshire customers, UES was able to release resources to other New England utilities. Demobilization efforts began throughout the day on Wednesday, November 1st. Working with NAMAG, resources were released to other regional utilities, including six (6) internal line and 11 contract crews sent to Eversource New Hampshire. By the evening of Wednesday, November 1st, the Company had released contracted line crews to three (3) utilities in three (3) states, including the 17 in New Hampshire.

Q. Did the Company complete an After Action Report for UES following October storm?

A. Yes. The UES "After Action Report" is provided as Schedule RLF-1 (Oct 30 2017 Storm Event AAR). This report provides a more detailed summary of the restoration regarding the October 30, 2017 storm.

IV. QUALIFYING MAJOR STORMS

Q. Why is October 30, 2017 event considered to be a major storm?

A. The Commission has established criteria for each utility in New Hampshire, based on the number of "troubles" and the percentage of customers interrupted, under which a severe weather event would be classified as a "major storm." Troubles are defined as interruption events occurring on either primary or secondary lines. Because the criteria incorporate information about the number of trouble locations (the number of individual outages) in addition to the number of customers interrupted, large outages caused by non-storm events cannot exceed the defined thresholds and are, thus, screened out. These definitions have worked well for over a decade and ensure that only significant storms meet the criteria for a major storm.

Q. How does the Commission define a qualifying major storm for UES?

A. Consistent with the definition in the Company's Major Storm Cost Reserve, qualifying major storms include severe weather events causing 16 concurrent troubles (interruption events occurring on either primary or secondary lines) and 15 percent of customers interrupted, or 22 concurrent troubles, in either the Capital or Seacoast regions of UES. The Company undertakes planning and preparation activities in advance of severe weather, if a qualifying major storm is likely to occur. The Company can also recover preparation costs if a major storm is considered likely to occur when an Energy Event Index ("EEI")[1] from the

[1] EEI levels are indices developed by Unitil's weather forecast provider – DTN. An EEI level is a qualified indicator of both the possibility and severity of a particular weather event that results in the potential for customer outages.

Company's professional weather forecaster reaches an EEI level of 3[2] or greater with a "high" (greater than 60 percent) level of confidence.

Q. Did the October storm meet the definition of a qualifying major storm?

A. Yes. During the October storm, UES experienced the following impact: approximately 180 concurrent troubles interrupting 64% of customers in the Capital Region; 104 concurrent troubles interrupting 72% of customers in the Seacoast Region. The numbers are significantly greater than the thresholds defined under the Commission definition. In addition, the event was forecasted on October 29th to have an EEI of 3 with a "High" level of confidence.

Q. Is the Company seeking recovery of the costs of October Wind storm through the Major Storm Cost Reserve ("MSCR")?

A. No. As explained in Testimony of Mr. Chong, the MSCR was established to deal with the more frequent ("typical") major storms that have a higher probability of occurring on an annual basis. It was not designed to include low frequency storms that are extraordinary in magnitude, such as Sandy. The reserve established in DE 10-055 (initially $400,000) in the amount of $800,000 (revised in docket DE 13-065) annually was not set at a level that would be sufficient to recover the costs of storms such as Sandy. If this cost ($1,233,742 of expense) were added to the

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[2] An EEI level of 3 is defined by weather conditions meeting any combination of the following criteria – strong storms where isolated yet severe pockets are possible with moderate to severe lightning; icing between 3/8 to 3/4 inch accretion; less than 6 inches of heavy wet snow; soil moisture greater than 6 g/kg; sustained winds of 30 to 40 mph with many wind gusts between 40 to 50 mph, and with a few in excess of 50 mph.

MSCR, the reserve would be in a significant deficit (over $4.5M) for an extended period of time.

Q. For what activities and costs is the Company seeking recovery?

A. The non-capitalized portion of the costs of restoration activities including: contractor crews, incremental compensation of employees, meals, lodging, and related expenses are included in the Company's filing. In addition, planning and preparation activities in advance of the storm including: pre-staging of crews, standby arrangements with external contractors, incremental compensation of employees, and other costs to prepare are also included.

V. CONCLUSION

Q. Please summarize your testimony.

A. To summarize, UES had a successful restoration, restoring service to 95% of its customers in approximately 36 hours, and all of its customers within 48 hours. UES's response over the past several major storms has demonstrated the Company's commitment to providing reliable service to its customers, including efficient and cost effective restoration services. The ability to pre-stage resources and, subsequently, release the same resources to support surrounding utilities has benefited not only our customers but also the state overall. This event was significant to the people of New Hampshire and far exceeded the major storm threshold. In light of the Company's performance and the fact that October wind event far exceeded the Commission definition of a major storm event, the Company respectfully requests the adjustment to the SRAF, as described in my testimony.

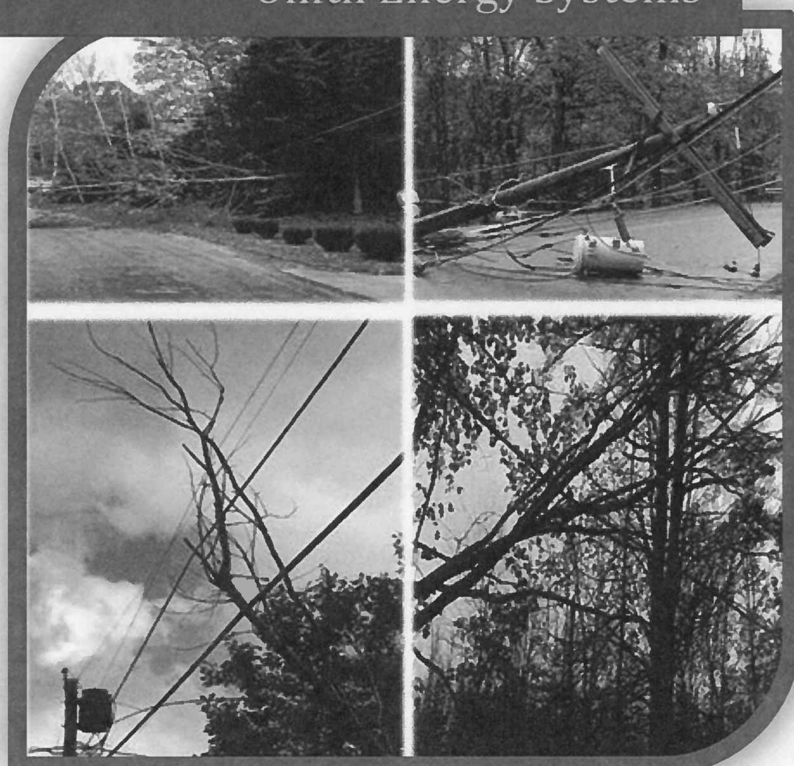
Q. Does this conclude your testimony?

A. Yes, it does.

Unitil

October 2017 Wind Event After Action Report

Unitil Energy Systems



Emergency Management

February 2018

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Executive Summary

Weather Overview & Preparedness Activities

Figure 1 - Wind Advisories

On Thursday October 26th, weather forecasters began reporting the possibility of a significant storm system expected to impact the northeast late Sunday (Oct 29th) into Monday (Oct 30th) with heavy rain, lightning and gusty winds. As the storm progressed over the weekend, forecasters increased the severity and likelihood of the event; predicting moderate to heavy amounts of rain (1-3") and frequent gusts between 35-50 mph with isolated gusts up to 60 mph across the service territory. Most at risk for high wind gust was the Company's Seacoast region. High wind watches and warnings were issued for nearly all portions of the northeast especially for coastal parts of RI, MA and NH.

In response to the forecasted winds, Unitil began holding daily coordination conference calls beginning on Friday (the 27th) with key logistical internal personnel to coordinate preparation activities in response to the pending wind event. Based on the forecasted weather and potential for outages, the Company began issuing its preparatory communication messages, and initiated contact with life support customers, regulators, emergency response, and municipal officials the following day. The EOCs were outfit prior to the storm and quickly took local control once the amount of outages exceeded the capabilities of the centralized dispatch center. The Seacoast and Capital EOC's were opened in advance of the weather event (Sunday evening) with the System EOC opening at 6 AM on Monday (the 30th) to provide essential logistical and communications support for responding resources.

Unitil's resource acquisition begins with confirming the availability of its internal line crews and support staff as well as on system contractor resources. Once the Company confirmed its normal contingent of UES internal crews (10) and on system contractors (11), it secured an additional 55 contractor line crews, 15 external tree crews, 9 damage assessors and 18 wire down guard to be available Monday morning (Oct 30th). Additionally, Unitil participated in routine, North Atlantic Mutual Assistance Group (NAMAG) calls beginning on October 30th to request additional resources however due to the storms region wide impact, the company was only able to acquire an additional 6 crews through the mutual aid process that could support the restoration in a timely manner. Ultimately, the acquired contracted resources were redirected to another Company as restoration progress was made sooner the resources projected arrival time.

System Impacts & Restoration

Scattered outages occurred across both of Unitil's NH service territories which were mostly attributed to tree damage and branches on powerlines. Peak interruptions occurred at approximately 5:19 AM on Monday, October 30th with 33,354 customers impacted (43% of Unitil's NH customers) with a cumulative total of 53,332 customers being impacted through the event.

The Company was challenged during the early phases of restoration due to ongoing hazardous winds that prevented line crews from safely raising the buckets[1]. There were multiple periods when the wind exceeded the safe threshold preventing line work that delayed the response. This delay can be measured in hours across both DOCs. Once the winds dropped below hazardous levels, crews were capable to respond to outages, with power being restored to 95% of the customers by 5pm on Tuesday (Oct 31st) and the majority of customers (99%) by noon on Wednesday (Nov 1st) with any remaining customer taking service once electricians completed work.

This storm was the fourth most devastating storm in terms of customer outages to impact NH. With the storms passing nearly 1.4 million customers were without power in the northeast due to severe flash flooding and tree damage (actual damage photos below). Upon completion of its restoration on Wednesday, Nov 1st, Unitil assisted neighboring utilities by releasing the majority of its external line crews, and sending 6 internal crews to Eversource Energy's New Hampshire region to assist in restoration.




Figures 2 - 5 – Damage Photos (Oct Wind Event)

[1] The company guidance is that buckets should not be raised when wind speeds exceed 35MPH unless it's a life threating situation and then only if the operator feels safe.

Challenges & Lessons Learned

Following the event, the Company held a formal event review with key response personnel to identify any lessons learned or areas for future improvement that were noted throughout the response.

The following strengths were noted throughout this event:

- Pre-staging of resources prior to the impact of the event aided in the ability to mobilize resources to the field quickly and develop work shifts once resources were safely able to respond;
- The collaboration between the Company and the NH State HSEM greatly improved the ability and timing to secure Canadian resources. Specifically, collaboration included the assistance in completion of Border Crossing documents that expedited movement of crews;
- The use of the iRestore application by the municipal responders provided damage pictures and locations which aided in identifying priorities and awareness of actual field conditions. Additionally, these pictures were easily divided by line and tree work and used to send the right type of restoration resources to the exact location while also providing a visual aid to customers on social media; and
- Though subjective the Company believes the Storm Resiliency Trimming Program reduced the number of tree related outages and had an overall positive impact on the time to restore customers.

Although the Company restored power to nearly 99% its impacted customers within 48 hours, several areas for improvement were identified for follow up:

- Logistical Coordination – The process should be evaluated to streamline logistical activities such as storm kit materials, onboard check-in, and meal delivery/setup;
- EOC Setup Documentation – Improve documentation for ensuring all tasks are completed prior to opening an EOC including technology specifications and requirements and the seamless decentralization of all tasks; and
- Outage Management System – Additional training and increasing the pool of staff that can operate OMS for large scale outage would be beneficial including system specific issues/configurations and leveraging additional technology (AMI) to ensure data integrity;

Weather Forecast Overview

Beginning on October 26th (Thu), weather forecasters began reporting a significant storm system expected to impact the northeast late Sunday (Oct 29th) into Monday (Oct 30th) with heavy rain, lightning and gusty winds. As the storm progressed through the weekend, forecasters increased the severity and likelihood of the storm system predicting moderate to heavy amounts of rain (1-3") and frequent gusts of between 35-50 mph with isolated gusts predicted up to 60 mph across the entire service territory. High wind watches and warnings were issued for nearly all portions of the northeast especially for coastal parts of RI, MA and NH.

On October 29th and 30th, 2017 a strong low pressure system moving in from the Great Lakes region, along with the remnants of Tropical Storm Philippe combined to produce a long duration event of strong wind gusts, significant rain, and thunderstorms. There were two periods of significant wind gusts, the first between 8pm Oct. 29th through 5am Oct. 30th in which wind gusts of 45-70 mph were reported. The second period of wind occurred between 9am-6pm on Oct. 30th where wind gusts of 40-55 mph were reported. Periods of moderate to heavy rain, along with embedded thunderstorms, also occurred from the morning of Oct. 29th through midday of Oct. 30th. The timing of these hazardous winds prevented restoration progress immediately following the customer peak however once safe, resources were quickly mobilized to the field.

Unitil has tailored weather forecast through its primary weather vendor (DTN) while also leveraging publicly available weather information channels for additional input. Nearly all weather outlets were forecasting high wind gusts across the service area. In general, the forecast was accurate for the Seacoast area but underestimated the inland expansion of the high winds. A sample of DTN's weather forecast displayed below. As outlined, we had expected level 2 winds in the Capital area which was identified with high confidence as late as the 30th but, in reality saw gust that exceeded level 2 and were actually level 3 gusts. See Attachments 1 and 2 for DTNs Weather Event Review and Hourly Wind Data.

Date: October 30, 2017
Time: 6:00 AM EDT
Forecaster: Nate Hamblin

Zones	SEACOAST	CAPITAL	FITCHBURG	PORTLAND
Event Starting in 30hrs	WIND	WIND	WIND	RAIN/WIND
Event Begin Time	6AM MON	9AM MON	9AM MON	6AM MON
Event End Time	6PM MON	6PM MON	6PM MON	7PM MON
Tstrm Wind Gusts				
Ltng Intensity				
Storm Mvmt Dir				
Rain Amount				1.50-3.00"
Snow Amount				
Snow Character				
Ice Amount				
Sustained Winds	22-30 mph	18-28 mph	18-28 mph	22-30 mph
Common Gusts	32-45 mph	30-40 mph	30-40 mph	32-45 mph
Peak Gusts	45-60 mph	40-45 mph	40-45 mph	45-60 mph
Chance EEI-2 Gusts	100%	80%	80%	100%
Chance EEI-3 Gusts	100%	-	-	100%
Temp. Extremes	62/40	62/36	64/40	61/38

Energy Event Index for UNITIL
Valid Time: October 30, 2017 6:00 AM EDT

Parameter	Region	Day 1	Day 2	Day 3
Wind Speed	Capital	1	1	1
	Fitchburg	1	1	1
	Portland	2	1	1
	Seacoast	2	1	1
Wind/Gust	Capital	2	1	1
	Fitchburg	2	1	1
	Portland	3	1	1
	Seacoast	3	1	1
Confidence Level	Capital	High	High	High
	Fitchburg	High	High	High
	Portland	High	High	High
	Seacoast	High	High	High

Energy Event Index Definition
With Leaves (Apr 1 - Nov 14)

EEI	Wind Speed	Wind/Gust
1	< 30 mph	< 35 mph
2	>= 30 mph	>= 35 mph
3	>= 45 mph	>= 50 mph
4	>= 60 mph	>= 65 mph
5	>= 70 mph	>= 75 mph

UNITIL SERVICE AREA 48 HOUR OUTLOOK:

CAPITAL: Scattered lighter rain showers will swing through later this morning. Additional rainfall: 0.10-0.20". Otherwise, dry weather will be likely through tonight. Hazard winds will be likely, detailed above. Wind direction: Becoming west-southwest. Winds could gust to 20-25 mph tonight at times. Dry weather is expected Tuesday and Tuesday night. Winds could gust to 20-30 mph during the day before going light at night. No hazards.

Confidence: Confidence is high that hazard winds will occur today. See table above for EEI gusts chances. Otherwise, confidence is high that no hazard conditions will occur tonight through Tuesday.

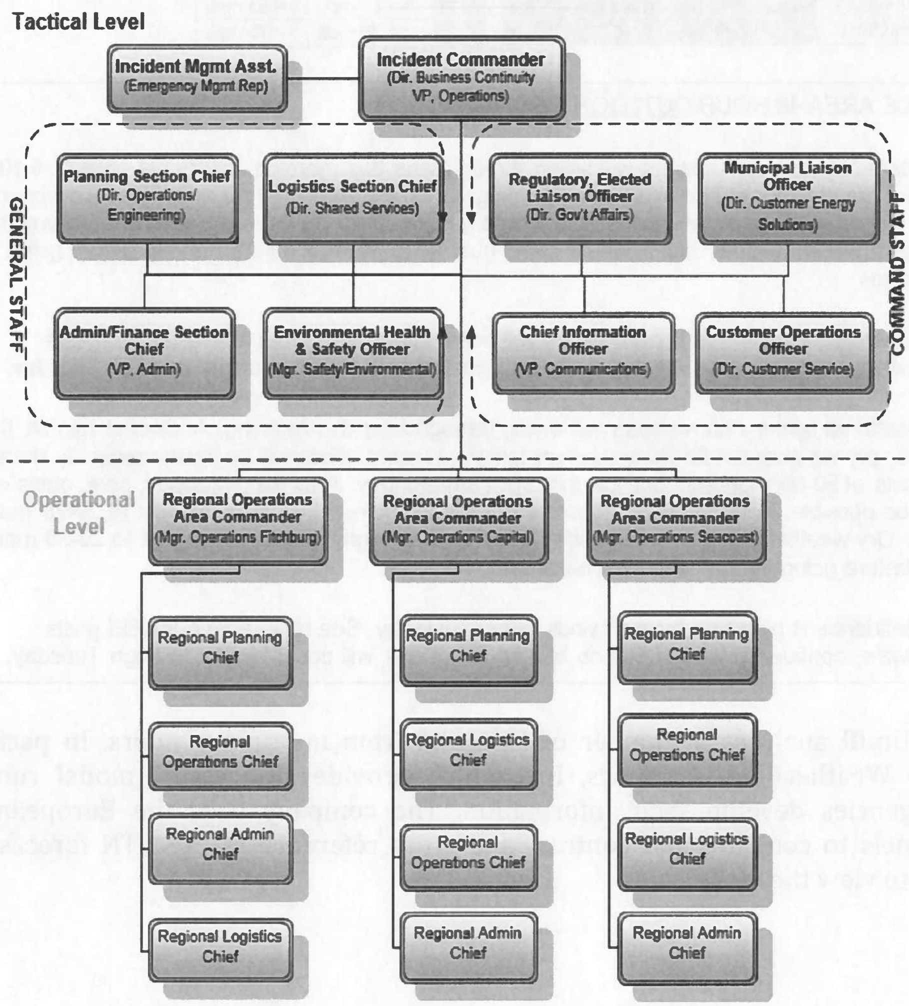
SEACOAST: Scattered lighter rain showers will swing through later this morning. Additional rainfall: 0.10-0.20". Otherwise, dry weather will be likely through tonight. Hazard winds will be likely, generally detailed above. Peak gusts of 50-60 mph will continue through 7am Monday. After 7am Monday, peak gusts of 45-50 mph will be possible. Wind direction: Becoming west-southwest. Winds could gust to 20-25 mph tonight at times. Dry weather is expected Tuesday and Tuesday night. Winds could gust to 20-30 mph during the day before going light at night. No hazards.

Confidence: Confidence is high that hazard winds will occur today. See table above for EEI gusts chances. Otherwise, confidence is high that no hazard conditions will occur tonight through Tuesday.

Additionally, Unitil analyzes a number of forecasts from multiple vendors. In particular, Unitil subscribes to WeatherBELL Analytics, Inc. which provides the actual model runs that most forecasting agencies develop their information. The company uses the European model and American models to compare and contrast and cross reference to the DTN forecast. Please see Attachment 3 to view the model runs.

Preparedness Activities & Communications

In response to the forecasted winds, Unitil began holding daily coordination conference calls beginning on Friday (the 27th) with key internal personnel to coordinate preparation activities. Based on the forecasted weather and potential for outages, the Company began issuing its preparatory communication messages and initiated contact with life support customers, regulators, emergency response, and municipal officials. The EOCs were setup prior to the storm and quickly took local control. The Seacoast and Capital EOC's were opened in advance of the weather event (Sunday evening) with the System EOC opening at 6 AM on Monday (the 30th) to provide essential logistical and communications support for responding resources.



Figures 6 – Unitil ICS Structure

The Communication team crafted public service announcements to distribute routinely prior to and throughout the event to provide important safety and contact information and detail restoration progress. These messages began on Saturday, Oct 28th with preparation messages and were updated twice daily throughout the event with additional information for a total of 7 PSAs being disseminated through various media channels (news and social media). In addition, the Company leverages its social media channels (Twitter/Facebook) to share additional messages and communicate with customers with over 50 messages being broadcast (examples follow).

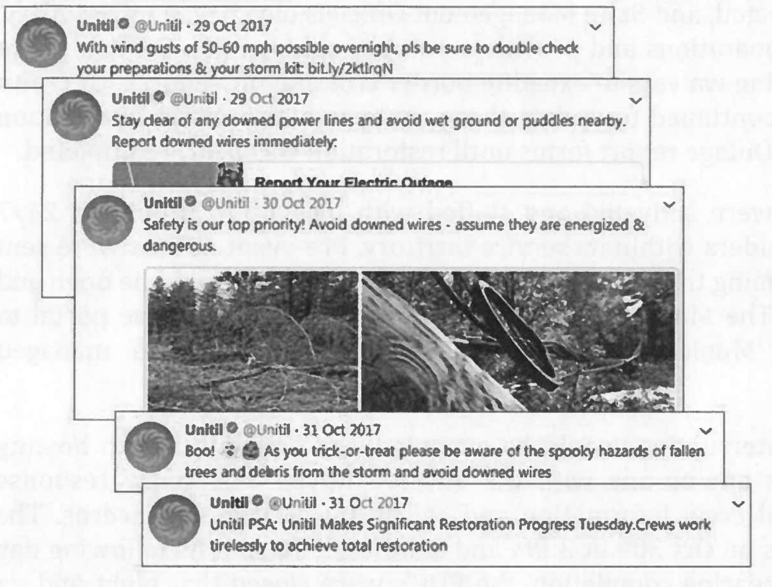


Figure 7 - Social Media Posts

Social Media Statistics		
	Facebook	Twitter
Existing Followers/Fans	11, 609	
New Followers/Fans	311	276
Messages Posted/Sent	55	325
Messages Received	844	370

Figure 8 - Social Media Statistics

A common theme of major events is an expected growth in followers or "fans" on the Company's social media account which was also noted throughout this event. Overall, the Company saw a 5.3% increase in its follower and fan base (see Figure 8 above) which allows for more interaction with the affected public and the Company's messaging to be broadcast to a larger audience. Unitil has a dedicated Communications team to manage the Company's social media accounts, which has proved very helpful for providing information and communicating with customers during emergency events.

Life Support customers (LSCs) were contacted by the Customer Service Center prior to the expected impact to provide safety and contact information in the event of a service interruption. Nearly 35,000 customer calls were made to the customer call center throughout the event in addition to online outage reporting with the following CSC call statistics provided:

Outage Statistics October 30, 2017

		PORCHE IVR			* IVR/CSC Service Level (Combined)	SIEMENS Phone System/CSC					
Date	Time	Total # of calls in the IVR	# Selecting Outage Option (update or ticket)	% Reporting Outage	% Answered in 20 Sec	# CSR Calls Received	# CSR Calls Answered	% Customers Opting out of IVR	# Abnd	Avg Wait Time	Peak Staffing
30-Oct	12am-12pm	21,022	15,874	76%	99%	5,148	4,591	24%	547	0:35	17
	Daily Total	**21,022**	**15,874**	**76%**	**99%**	**5,148**	**4,591**	**24%**	**547**	**0:00**	**17**
31-Oct	12am-12pm	3,795	2,134	56%	99%	1,661	1,585	44%	66	0:18	18
	Daily Total	**3,795**	**2,134**	**56%**	**99%**	**1,661**	**1,585**	**44%**	**66**	**0;**	**18**
1-Nov	12am-12pm	2,041	657	32%	97%	1,384	1,226	68%	139	1:06	17
	Daily Total	**2,041**	**657**	**32%**	**97%**	**1,384**	**1,226**	**68%**	**139**	**0:07**	**17**
	Storm Total	**26,858**	**18,665**	**69%**	**99%**	**8,193**	**7,402**	**45%**	**752**	**0:03**	**52**

Figure 9 - Customer Call Center Statistics

Communications with Regulatory, Elected, and State Management Officials also began on Saturday, Oct 28th to notify them of Unitil's preparations and provide a point of contact. The Company also worked with NH HSEM staff on securing waivers to expedite border crossing procedures for crews coming from Canada. The Company continued to update these contacts with routine information including the required PUC Crew and Outage report forms until restoration was nearly completed.

The Municipal Rooms in each EOC were activated and staffed with liaisons to provide a 24/7 available contact for municipal responders within its service territory. Pre-event notices were sent to all Municipal Official contacts informing them of the time the Municipal Room would be open and the means to contact the Company. The Municipal Rooms also monitored the iRestore portal to ensure any reports submitted by Municipal Officials via the mobile app were managed appropriately.

Once it was known that customer interruptions could be extended, the Company began hosting Municipal Conference calls to speak one-on-one with the affected towns emergency response personnel to provide restoration and crew information and solicit any issues or concerns. The Capital and Seacoast Region held calls on Oct 30th at 3 PM and another at 10 AM the following day (Tues, Oct 31st). As restoration was nearing completion, the EOC's were closed that night and no further municipal calls were held however Operations worked closely with municipalities on any outstanding issues or follow up work.

Event Impact & Restoration Overview

Scattered outages occurred across both of Unitil's NH service territories which were primarily related to tree damage and branches on powerlines. The Company had retained additional resources, however ongoing hazardous winds initially prevented line crews from safely raising buckets to respond. Peak interruptions occurred at approximately 5:19 AM on October 30th with 33,354 customers impacted (43% of Unitil's NH customers) with a cumulative total of 53,332 customers being impacted through the event. Although the Capital Region experienced more outages (locations of damage), the Seacoast Region experienced a larger customer impact. The first outage occurred on Oct. 29th at 7:50 PM and the last customer was restored at Nov. 1st at 5:54PM; however the majority of impacted customers (95%) were restored by 6 AM on Nov 1st.

Table 1 – Regional Impact Summary

	Seacoast Region	Capital Region
# Trouble Locations (Total)	167	237
# Cust. Impact (Peak)	21,857	12,479
# Cust. Impact (Cumulative)	34,007	19,325
# Ft. Wire Replaced	1842	2867
# Poles Replaced	9	8
# Cross Arms Replaced	13	15
# Transformers Replaced	8	32

Reports of wires down or other hazardous electrical equipment were reported to the Company through various means (customer calls, municipal official reports, online reporting, and iRestore) with at least 136 reports received throughout the event. Unitil tracked each reported instance in a SharePoint data base and worked closely with municipal first responders to ensure any Priority 1 calls (life threating in nature) were responded to immediately. Our goal, as always, is to ensure the public is safe and to free municipal first responders from the task of standing-by a down wire. As usual, many (we estimate 50%) of the wires were not electrical in nature; however all were responded to appropriately.

The Company also utilizes a mobile application (iRestore) that allows approved Municipal Officials to send follow up pictures and locations of damage via their smartphones after they have notified the Company. The Regional Municipal Room monitored the iRestore portal during the event, matching the received reports with municipal calls.

The Company found this process, which it has incorporated into the wire-down response procedure, extremely useful in helping it determine the urgency of response and the right resources to send based on the type of damage. The Company received 30 reports through the iRestore application during the wind event and used some of these pictures on social media as talking points to explain customer damage as shown in the following image.

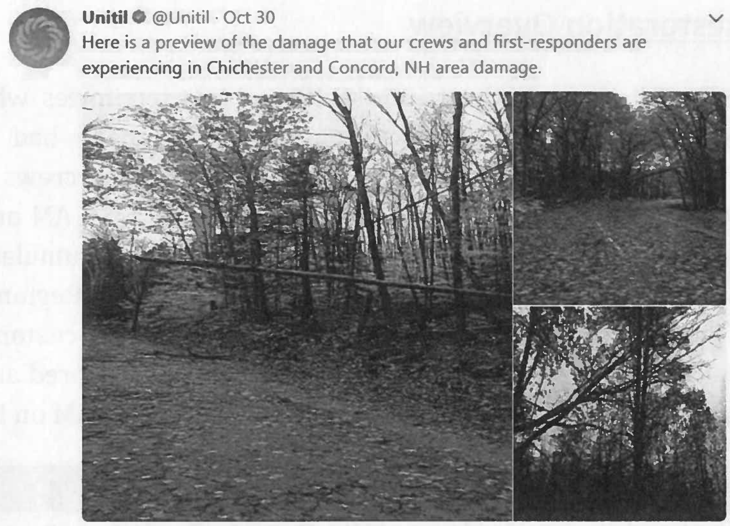


Figure 10 – iRestore Photo Social Media Use

Though subjective, the Company believes the Storm Resiliency Trimming Program reduced the number of tree related outages and had an overall positive impact on the time to restore customers. Once the winds dropped below hazardous levels, crews responded to outages with power being restored to the majority of customers (95%) by 6 AM on Wednesday (Nov 1st) and the remaining customer restored throughout the remainder of the day. The majority of damage was caused by tree limbs and debris coming into contact with electrical equipment. The first outage occurred on Oct. 29th at 7:50 PM and the last customer was restored at Nov. 1st at 5:54PM; however the majority of impacted customers (95%) were restored by 6 AM on Nov 1st.

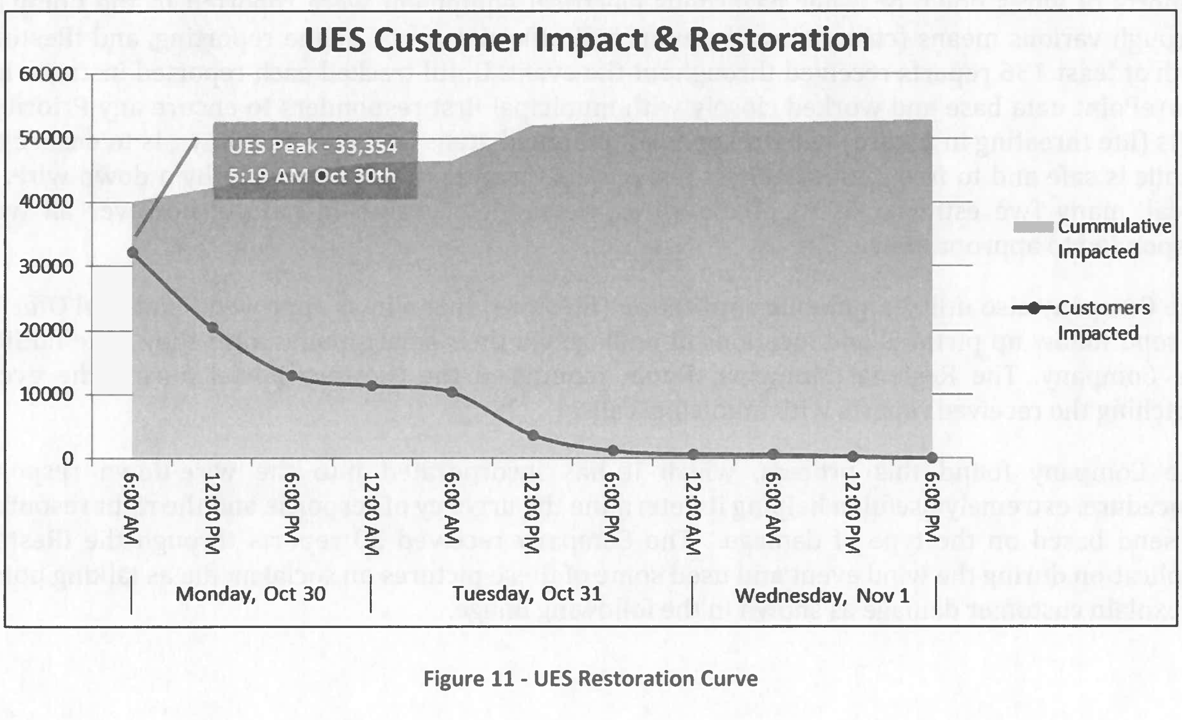


Figure 11 - UES Restoration Curve

Resource Availability

Once Unitil was aware of the escalating weather conditions it began securing additional local crews to be on property prior to impact. As outages began to spread across the Region, and resources became scarce, the North Atlantic Mutual Assistance Group (NAMAG) was activated (which also quickly notified neighboring RMAGs) as several impacted member Companies were in need of additional resources. NAMAG calls were held at the following times: Oct 30th 8 AM and 1 PM; Oct 31st 9 AM and 7 PM; Nov 1st 9:30 AM. However, resource requests could not be fulfilled through NAMAG as all member utilities were either requesting or holding and it was necessary to acquire resources from neighboring RMAGs (Great Lakes Mutual Aid and Southeast Exchange Mutual Aid Groups); this required further travel and increased response times. The Company was able to retain resources from Canada to ensure it had an adequate amount for restoration and coordinated with the NH HSEM to initiate border crossing procedures.

Table 2 details the amount of resources at peak (max) for the event while Figure 12 displays the availability of resources over the event.

Table 2 – Peak Resource Numbers

Crew Type	# Crews	# FTEs
Internal Line	12	24
External Line	55	110
Tree	15	30
Damage Assessor	9	9
Wires Down	18	18
Support Personnel	≈80	≈80

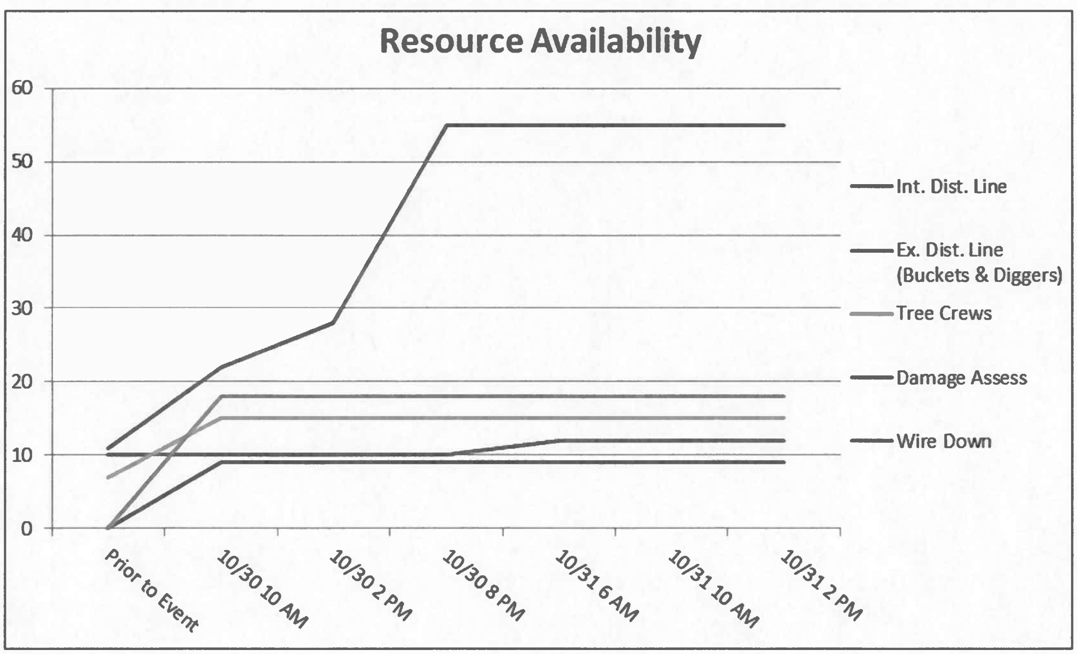


Figure 12 – Resource Availability Overview

Additionally, once The Company was near the end of its restoration, it redeployed the majority of its additional contractor line crews through NAMAG to support neighboring utilities still requiring resources. The Company was able to ensure crews released were redeployed to nearby utilities and also sent 6 internal crews to assist Eversource NH in its restoration. After review of submitted resource reports issued during the event, minor adjustments were made with updated crew reports found in Attachment 6 to this report.

Event Costs

The Company's Administration/Finance Section Chief began tracking the cost of this event from the onset. The primary driver is the number of outside restoration resources acquired and related logistics such as food and lodging. The total expense cost associated with this storm is $1,233,742.

Challenges & Lessons Learned

Following the event, the Company held a formal event review with key response personnel to identify any lessons learned or areas for future improvement that were noted throughout the response. The following strengths and challenges were identified with resulting action items also listed.

Strengths

The following strengths were noted throughout this event:

- The use of the iRestore application by the municipal responders provided damage pictures and locations which aided in identifying priorities and awareness of actual field conditions. Additionally, these pictures were used to send the right type of restoration resources to the location and provided a visual aide to customers on social media.
- The collaboration between the Company and the NH State HSEM greatly improved the ability and timing to secure Canadian resources. Specifically, collaboration included the assistance in completion of Border Crossing documents that expedited movement of crews.
- Pre-staging of resources prior to the impact of the event aided in the ability to mobilize resources to the field quickly and develop work shifts once resources were safely able to respond.
- The company's Storm Resiliency Trimming Program reduced the number of tree related outages and clearly had a positive impact on the time to restore customers.

Challenges

Several areas for improvement were identified throughout the Company's response for follow up which are detailed below with resulting recommendation for improvement:

- Logistical Coordination – The process should be evaluated to streamline logistical activities such as storm kit materials, onboard check-in, and meal delivery/setup
    - Additional review and updating of logistical processes to incorporate changes and lessons learned/best practices
- Outage Management System – Additional training and increasing the pool of staff that can operate OMS for large scale outage would be beneficial including system specific issues/configurations and leveraging additional technology (AMI) to ensure data integrity
    - Additional staff identified and higher frequency of training to be provided to non-traditional OMS users
- EOC Setup Documentation – Improve documentation for ensuring all tasks are completed prior to opening an EOC including technology specifications and requirements and the seamless decentralization of all tasks
    - Review and update decentralization and EOC activation procedures to ensure additions or updates to technology and equipment are noted

Attachment 1 – DTN Weather Event Report

Analysis of the October 2017 Northeast Wind Event

Prepared by: Kris Haugen – Energy Team Lead, DTN Meteorological Operations

Summary of Events

On October 29th and 30th, 2017 a strong low pressure system moving in from the Great Lakes region, along with the remnants of Tropical Storm Philippe combined to produce a long duration event of strong wind gusts, significant rain, and thunderstorms. See Figure 1. There were two periods of significant wind gusts, the first between 8pm ET Oct. 29th through 5am ET Oct. 30th in which wind gusts of 45-70 mph were reported. The second period of wind occurred between 9am-6pm Oct. 30th where wind gusts of 40-55 mph were reported. Periods of moderate to heavy rain, along with embedded thunderstorms, also occurred from the morning of Oct. 29th through midday of Oct. 30th. Rainfall amounts of 1.50-5.00" were recorded. Another culminating factor to this event was the fact that many of the trees across the Northeast still had leaves on trees, along with a fairly saturated ground from a rain storm days prior to this event.

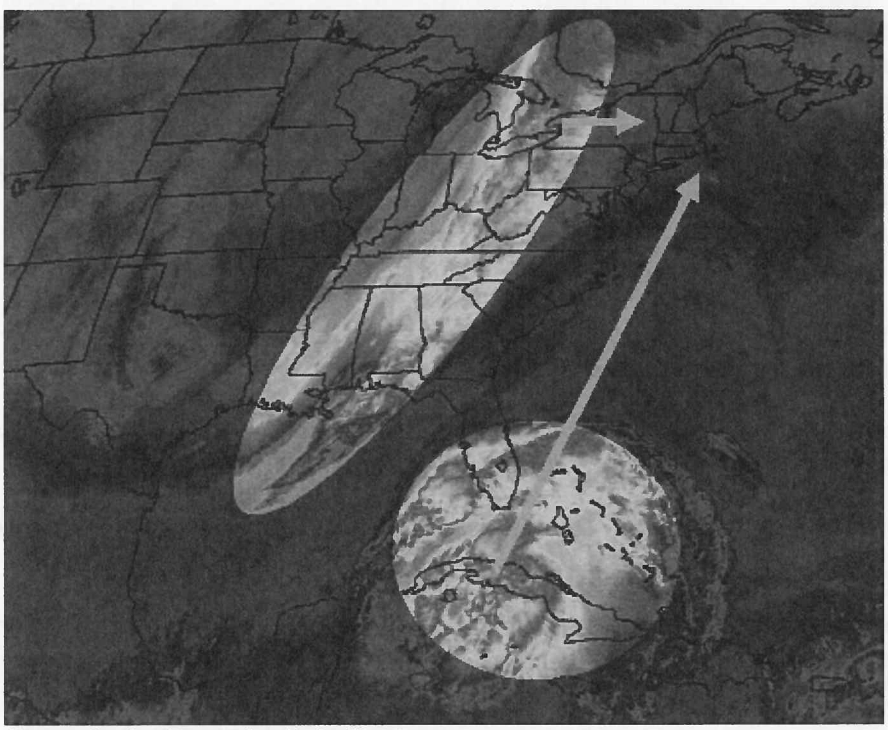


Figure 1: Infrared satellite image from October 29, 2017

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DTN Forecast

Thursday, October 26, 2017

As early as Oct. 26th the weather models were indicating a possible hazard wind gust event for the Northeast. However, there was disagreement regarding the timing and position of the low that was expected to develop as a result of the two weather systems combining. If the low were to develop along the Eastern Coast of the United States then a shorter duration and lessened wind gust impact would occur. However, if the low were to develop in the Hudson Valley of New York, as some models were indicating, then a longer duration and much higher wind gust impact would affect a much broader area of the Northeast. At this time DTN was reflecting a possible hazard wind gusts event, both inside and outside of thunderstorm activity, Sunday into Sunday night; and another period of gusty winds through the day on Monday.

New England (CT, RI, MA, NH & ME)	COMMON GUSTS	PEAK WIND GUSTS
Sunday & Sunday Night	35-45 mph	45-50 mph
Monday	40-50 mph	

New York	COMMON GUSTS
Sunday & Sunday Night	30-40 mph
Monday	40-50 mph

Friday, October 27, 2017

Moving into Oct 27th the weather models were starting to come into better agreement of a low developing in the Hudson Valley of New York, which increased DTN's confidence that this would be a longer duration and more widespread hazard wind event for the Northeast. There was also a slight shift in timing with the models showing the peak wind event occurring Sunday night into early Monday morning; and then another round of winds spiking during the daytime hours Monday. Subsequently, wind gusts were increased Sunday night into Monday morning across New England; while the forecast remained generally the same in New York with an adjustment to timing.

New England (CT, RI, MA, NH & ME)	COMMON GUSTS	PEAK WIND GUSTS
Sunday Night/Early Monday	40-50 mph	55-65 mph
Daytime Monday	40-50 mph	

New York	COMMON GUSTS
Sunday Night/Early Monday	30-40 mph
Daytime Monday	40-50 mph

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Saturday & Sunday, October 28-29, 2017

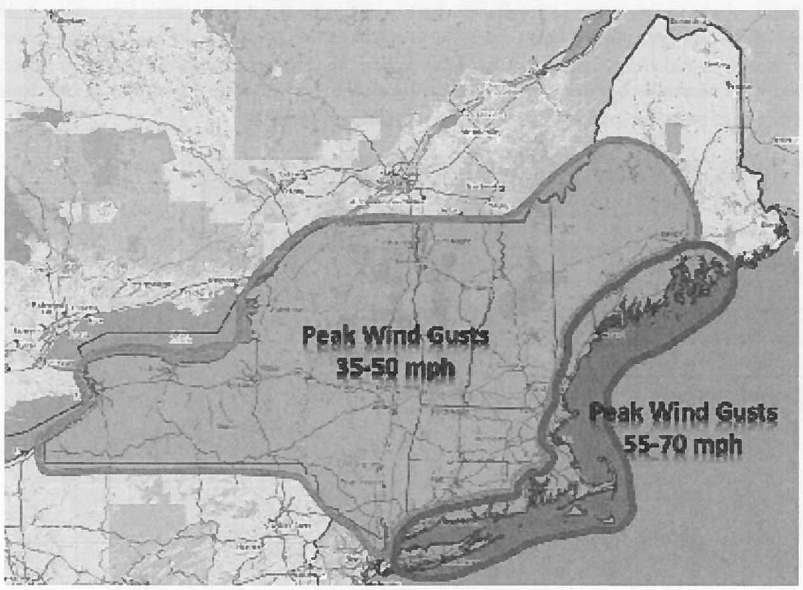
By Oct. 28th & 29th, the models were in good agreement on the timing, strength, and the Hudson Valley position of the developing low. This lead to higher confidence in the overall forecast for the Northeast. The strongest winds were expected Sunday night into early Monday morning, with the highest gusts expected across coastal areas.

New England (CT, RI, MA, NH & ME)	COMMON GUSTS	PEAK WIND GUSTS
Sunday Night/Early Monday	40-50 mph	50-65 mph
Daytime Monday	40-50 mph	

New York	COMMON GUSTS	PEAK WIND GUSTS
Sunday Night - Monday	30-40 mph	45-55 mph

Event Impact

Strong, hazardous wind gusts affected the majority of the Northeast Sunday night, Oct. 29th through Monday, Oct. 30th. The strongest wind gusts were recorded between 8pm ET Oct. 29th and 5am ET Oct. 30th, with gusts of 55-70 mph experienced along the Eastern Atlantic Seaboard from Long Island, NY and coastal Connecticut and up through coastal Maine. Wind gusts of 35-50 mph were experienced over the rest of the Northeast. A second period of wind gusts continued through the day on Monday making this a prolonged hazardous wind event, which downed trees and branches and caused numerous power outages. See images and tables below areas of peak wind gusts and timing.



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CONNECTICUT	PEAK GUST	TIME (Oct. 30)
Groton	66 mph	11:31 PM (Oct. 29)
Stamford	65 mph	1:36 AM
Bridgeport	58 mph	11:30 PM (Oct. 29)
Meriden	56 mph	1:06 AM
New Haven	51 mph	11:02 PM (Oct. 29)
New London	47 mph	12:36 AM

RHODE ISLAND	PEAK GUST	TIME (Oct. 29)
Block Island	71 mph	12.00 AM (Oct. 30)
Warwick	63 mph	11.29 PM
Barrington	62 mph	11.40 PM
Providence	61 mph	12.06 AM (Oct. 30)
Bristol	59 mph	10.00 PM
Newport	55 mph	10.35 PM

MASSACHUSETTS	PEAK GUST	TIME (Oct. 30)
Mashpee	93 mph	3:49 AM
Fairhaven	76 mph	2:50 AM
Wellfleet	72 mph	3:39 AM
Nantucket	70 mph	3:34 AM
Plymouth	68 mph	2:48 AM
Chatham	67 mph	3:29 AM
Taunton	67 mph	11:50 AM (Oct. 29)
Milford	67 mph	6:17 AM
East Falmouth	65 mph	1:29 AM
Barnstable	64 mph	3:12 AM
Milton	63 mph	12:38 AM
Boston	53 mph	12:43 AM
Hyannis	52 mph	3:46 AM
New Bedford	51 mph	12:05 AM
Williamstown	42 mph	4:52 AM
Pittsfield	41 mph	4:29 AM

NEW HAMPSHIRE	PEAK GUST	TIME (Oct. 30)
Meredith	68 mph	2:03 AM
Manchester	59 mph	1:45 AM
Mt. Washington Airport	58 mph	2:56 AM
Portsmouth	56 mph	5:45 AM
Skyhaven Airport	56 mph	5:05 AM
Berlin	51 mph	2:41 AM
Concord	51 mph	12:03 AM
Laconia	43 mph	12:07 AM
Lebanon	39 mph	3:44 AM

MAINE	PEAK GUST	TIME (Oct. 30)
South Bristol	71 mph	6:00 AM
Augusta	70 mph	8:05 AM
Portland	69 mph	6:09 AM
Denmark	64 mph	6:02 AM
Camden	54 mph	7:20 AM
Wells	54 mph	6.06 AM
Rangeley	51 mph	6:40 AM
Jackman	50 mph	7:46 AM
Auburn	47 mph	5:56 AM
Sanford	47 mph	4.53 AM
Knox Co. Airport	44 mph	5:53 AM
Eastern Slopes Airport	40 mph	2:25 AM
Waterville	39 mph	6.08 AM

NEW YORK	PEAK GUST	TIME (Oct. 30)
Waterford	52 mph	4:35 AM
Oswego	52 mph	7:45 AM
Wellsville	49 mph	5:56 AM
Schenectady	48 mph	11:30 AM
Albany	46 mph	4:51 AM
Batavia	46 mph	5:30 AM
Fredonia	45 mph	8:10 AM
Rochester	45 mph	7:45 AM
Watertown	43 mph	9:07 AM
Edinburg	41 mph	4:30 AM
Buffalo	38 mph	7:54 AM
Herkimer	37 mph	4:30 AM
Olean	35 mph	5:55 AM

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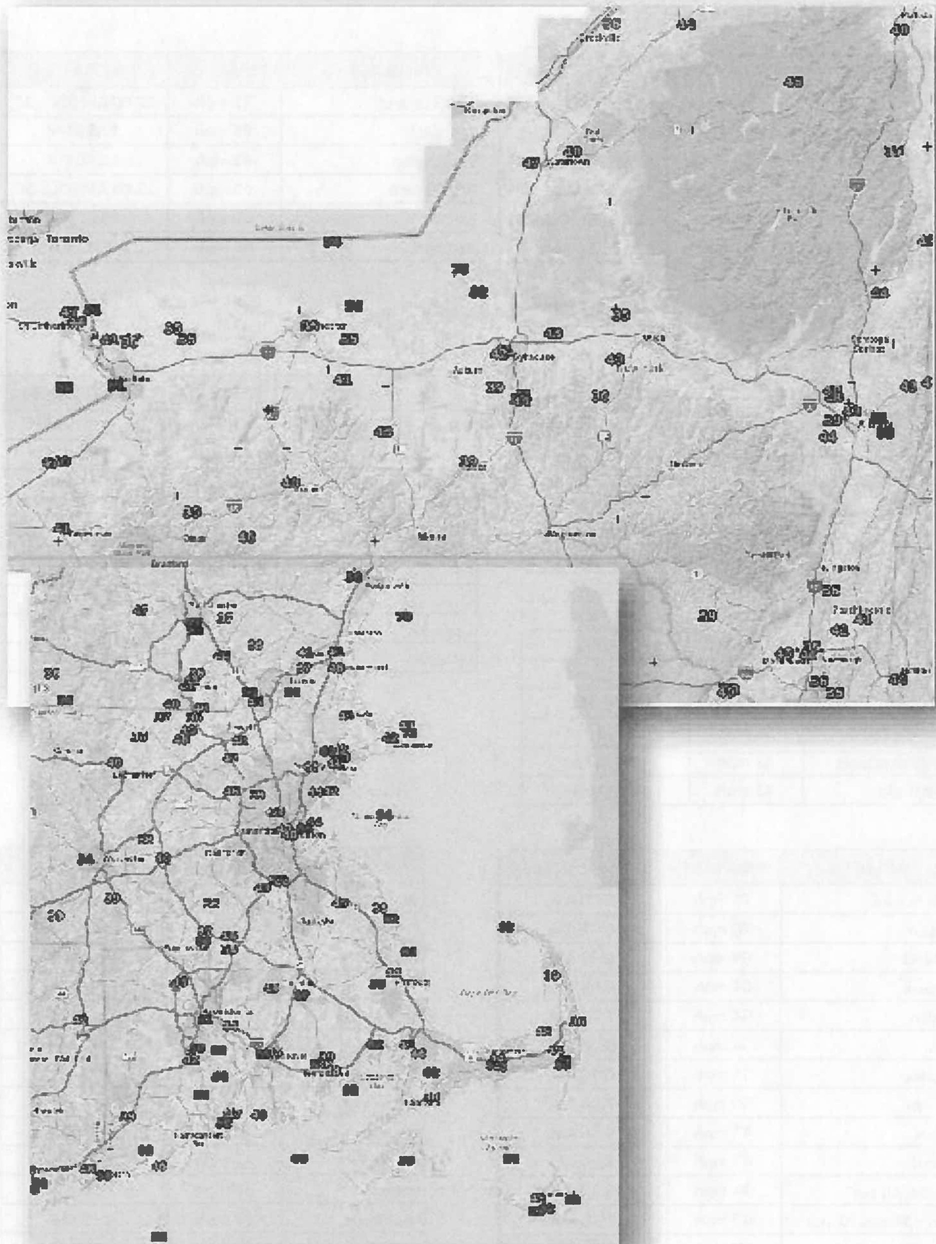

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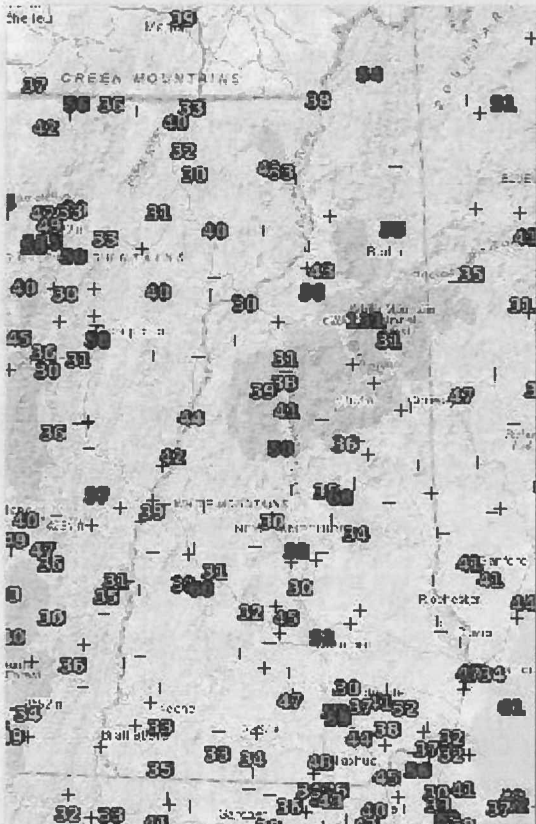

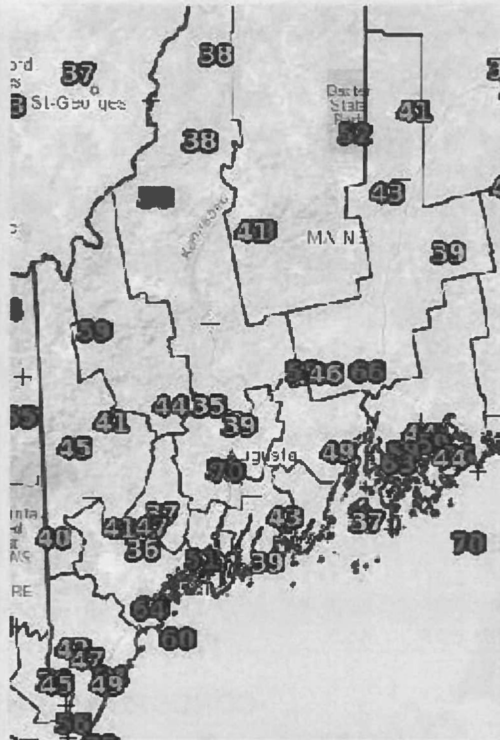

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Attachment 2 – Hourly Wind Speeds (DTN)

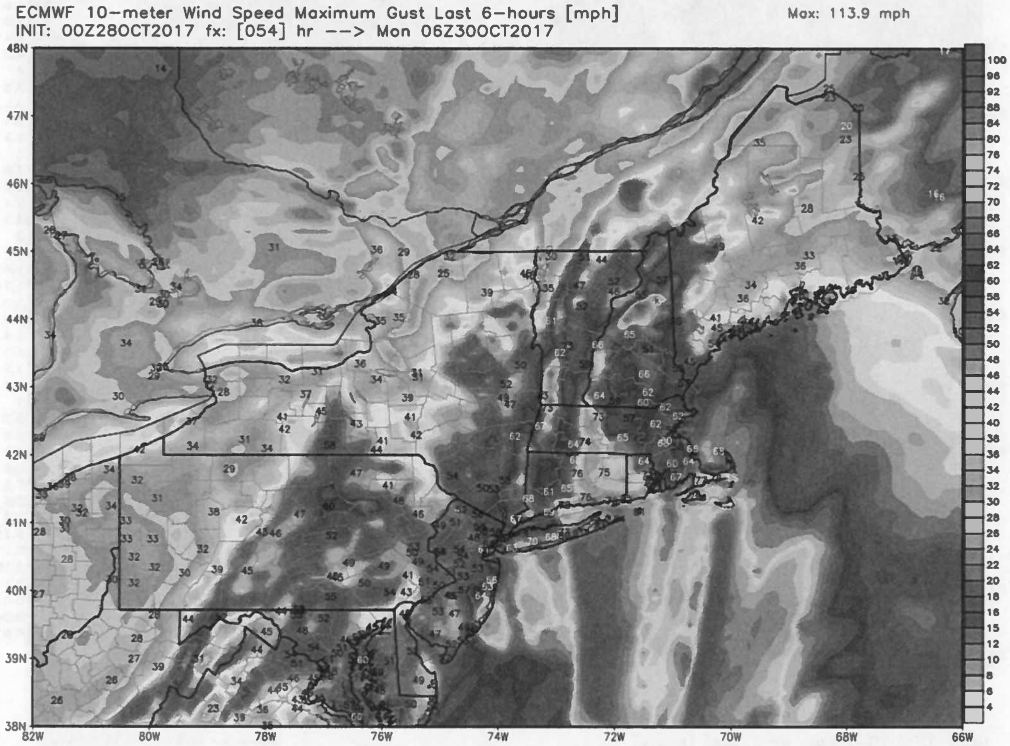
PORTSMOUTH (KPSM) for October 30, 2017

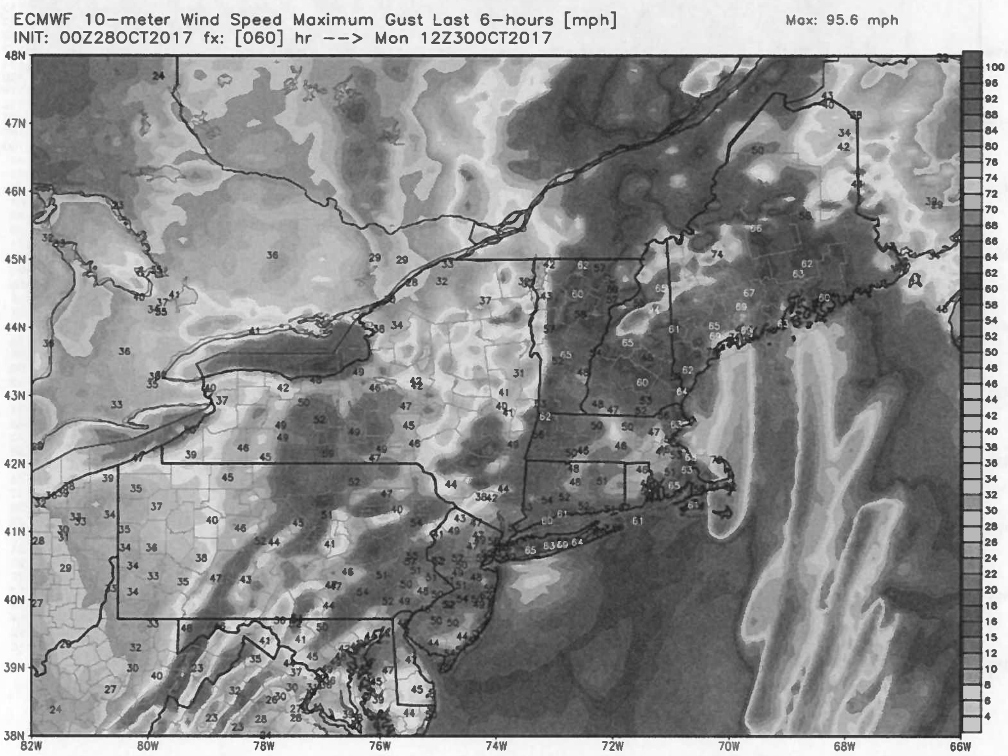
Hour	Temperature (°F)	Dew Point (°F)	Relative Humidity (%)	Precipitation (in.)	Wind (mph)	Conditions
12:00 AM EDT	60.1	58.6	97	0.13	E at 26 G 39	Rain
1:00 AM EDT	60.4	59.4	97	0.13	E at 29 G 40	Rain
2:00 AM EDT	61.5	59.7	93	0.37	ESE at 30 G 51	Rain
3:00 AM EDT	61.3	60.1	97	0.31	ESE at 31 G 48	Rain
4:00 AM EDT	61.5	60.1	93	0.62	E at 28 G 45	Rain
5:00 AM EDT	61.7	60.3	93	0.09	ESE at 36 G 53	Windy
6:00 AM EDT	61.9	60.4	93	0.00	SE at 36 G 56	Rain
7:00 AM EDT	62.1	60.3	93	0.00	SSE at 14 G 53	Mostly Cloudy
8:00 AM EDT	62.2	60.4	93	0.00	S at 10	Mostly Cloudy
9:00 AM EDT	62.8	59.2	87	0.00	SSE at 14 G 24	Cloudy
10:00 AM EDT	62.4	56.5	81	0.00	SSE at 20 G 30	Mostly Cloudy
11:00 AM EDT	62.2	51.1	67	0.00	S at 13 G 32	Mostly Cloudy
12:00 PM EDT	60.3	49.3	67	0.01	S at 17 G 36	Cloudy
1:00 PM EDT	54.5	51.3	86	0.00	WSW at 13 G 31	Showers
2:00 PM EDT	54.9	43.3	64	0.00	WSW at 21 G 38	Mostly Cloudy
3:00 PM EDT	55.6	41.0	57	0.00	WSW at 22 G 45	Mostly Cloudy
4:00 PM EDT	53.8	38.8	57	0.00	WSW at 22 G 36	Mostly Cloudy
5:00 PM EDT	53.6	36.0	51	0.00	WSW at 20 G 38	Mostly Sunny
6:00 PM EDT	51.3	34.2	52	0.00	SW at 10 G 30	Clear
7:00 PM EDT	50.5	33.6	52	0.00	WSW at 12 G 20	Clear
8:00 PM EDT	48.7	33.3	54	0.00	SW at 8	Clear
9:00 PM EDT	47.1	34.0	61	0.00	S at 7	Clear
10:00 PM EDT	47.3	34.9	63	0.00	SSW at 6	Clear
11:00 PM EDT	45.5	35.6	68	0.00	SSW at 3	Clear

CONCORD (KCON) for October 30, 2017

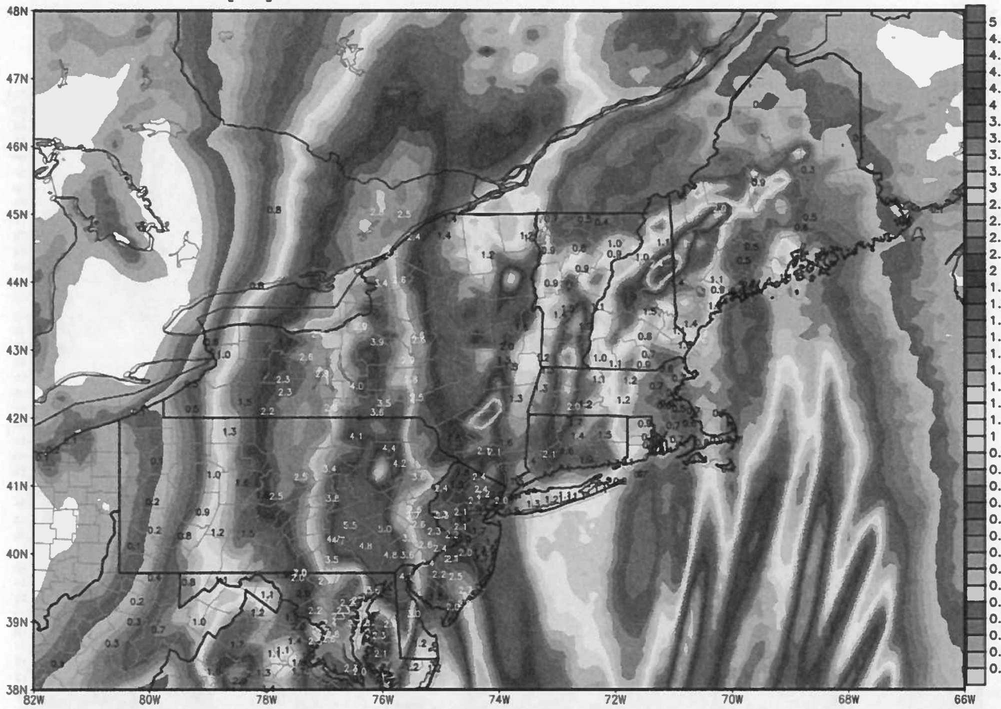
Hour	Temperature (°F)	Dew Point (°F)	Relative Humidity (%)	Precipitation (in.)	Wind (mph)	Conditions
12:00 AM EDT	63.0	60.1	90	0.29	ESE at 17 G 40	Rain
1:00 AM EDT	63.0	61.0	93	0.40	ESE at 16 G 51	Rain
2:00 AM EDT	63.0	60.1	90	0.20	ESE at 28 G 45	Rain
3:00 AM EDT	63.0	60.1	90	0.32	ESE at 24 G 49	Rain
4:00 AM EDT	63.0	61.0	93	0.23	ESE at 18 G 49	Rain
5:00 AM EDT	63.0	61.0	93	0.05	ESE at 18 G 40	Rain
6:00 AM EDT	63.0	61.0	93	0.00	SSE at 17 G 24	Rain
7:00 AM EDT	62.1	60.1	93	0.00	SSE at 17 G 29	Rain
8:00 AM EDT	61.0	59.0	93	0.00	SSE at 16 G 28	Rain
9:00 AM EDT	61.0	57.0	87	0.00	SSE at 14 G 23	Rain
10:00 AM EDT	63.0	55.0	75	0.00	S at 18 G 31	Rain
11:00 AM EDT	62.1	53.1	73	0.00	S at 17 G 29	Rain
12:00 PM EDT	61.0	51.1	70	0.00	SSW at 14 G 23	Rain
1:00 PM EDT	54.0	48.0	80	0.00	WSW at 9	Rain
2:00 PM EDT	53.1	45.0	74	0.00	W at 10	Rain
3:00 PM EDT	53.1	39.9	62	0.00	W at 17 G 37	Mostly Sunny
4:00 PM EDT	53.1	39.0	59	0.00	W at 12 G 38	Mostly Cloudy
5:00 PM EDT	52.0	35.1	52	0.00	SW at 13 G 35	Sunny
6:00 PM EDT	50.0	34.0	54	0.00	WSW at 15 G 20	Clear
7:00 PM EDT	48.0	34.0	59	0.00	SW at 5	Clear
8:00 PM EDT	44.1	35.1	71	0.00	SSE at 6	Clear
9:00 PM EDT	43.0	35.1	73	0.00	SSE at 7	Clear
10:00 PM EDT	43.0	36.0	76	0.00	SSE at 7	Clear
11:00 PM EDT	43.0	36.0	76	0.00	S at 7	Clear

Attachment 3 – WeatherBell Analytic Models



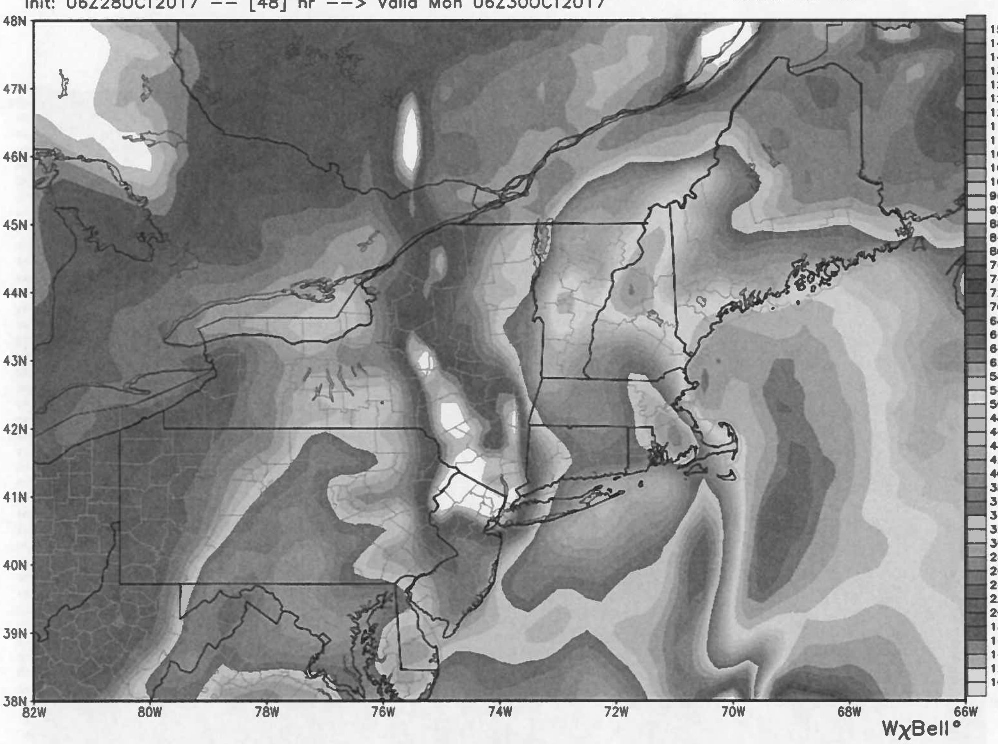


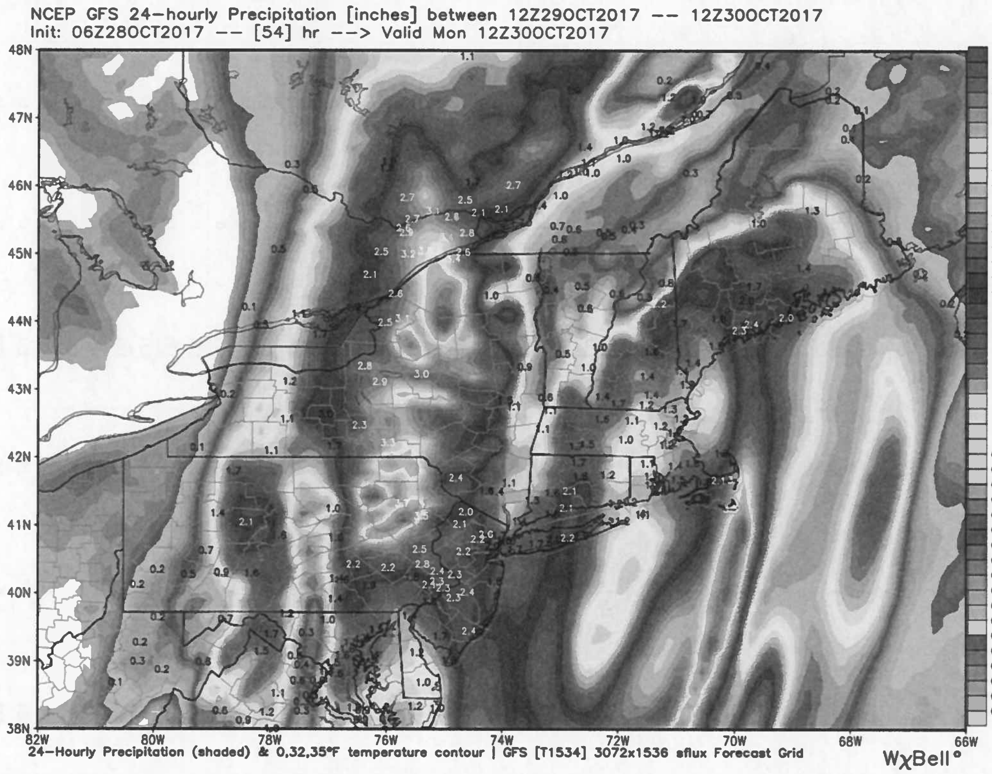
ECMWF 24–hourly Precipitation [inch] b/t 12Z29OCT2017 -- 12Z30OCT2017
INIT: 00Z28OCT2017 fx: [060] hr --> Mon 12Z30OCT2017



NCEP GFS 10–meter Wind Gust [knots]
Init: 06Z28OCT2017 -- [48] hr --> Valid Mon 06Z30OCT2017

Min|Max SLP: 975.2 hPa | 1012.3 hPa
MaxGust: 79.2 knots




NCEP GFS 24-hourly Precipitation [inches] between 12Z29OCT2017 -- 12Z30OCT2017
Init: 06Z28OCT2017 -- [54] hr --> Valid Mon 12Z30OCT2017
24-Hourly Precipitation (shaded) & 0,32,35°F temperature contour | GFS [T1534] 3072x1536 sflux Forecast Grid
WxBell

Attachment 4 – UES Customer Hourly Interruptions By Town (Capital Region)

	Allenstown	Boscawen	Bow	Canterbury	Chichester	Concord	Dunbarton	Epsom	Hooksett	Hopkinton	Loudon	Pembroke	Salisbury	Webster
10/29/17 8:00 PM	0	0	128	0	0	0	0	0	0	0	0	0	0	0
10/29/17 9:00 PM	8	0	128	0	127	0	0	6	0	0	23	0	0	0
10/29/17 10:00 PM	8	0	0	0	127	0	0	6	0	0	23	0	0	0
10/29/17 11:00 PM	8	0	1	0	127	0	0	68	0	0	23	0	0	0
10/30/17 12:00 AM	8	117	951	72	71	164	0	6	1	0	0	0	0	0
10/30/17 1:00 AM	8	270	989	484	1037	2051	1	1351	1	18	74	31	19	414
10/30/17 2:00 AM	13	398	1279	484	1037	3934	1	1480	1	18	134	31	34	414
10/30/17 3:00 AM	13	398	1631	487	1074	4478	1	1480	1	18	134	31	34	414
10/30/17 4:00 AM	13	398	1631	507	1074	4514	1	1480	1	18	134	31	34	414
10/30/17 5:00 AM	13	398	1631	507	1074	5734	1	1480	1	18	134	31	34	414
10/30/17 6:00 AM	13	398	1605	530	1074	5037	1	1480	1	18	134	31	34	414
10/30/17 7:00 AM	13	398	1605	530	1074	5053	1	1480	1	18	134	31	34	414
10/30/17 8:00 AM	13	398	1606	530	430	3656	1	567	1	18	131	0	34	414
10/30/17 9:00 AM	13	398	1607	507	480	2251	1	598	1	18	131	15	41	414
10/30/17 10:00 AM	13	398	1607	507	480	3094	1	598	1	18	131	15	41	414
10/30/17 11:00 AM	13	398	1608	507	480	2558	1	615	1	18	131	0	41	414
10/30/17 12:00 PM	13	399	1608	507	481	2641	1	619	1	18	131	0	41	414
10/30/17 1:00 PM	13	399	1000	498	504	2673	1	619	1	18	131	0	41	414
10/30/17 2:00 PM	13	399	1000	499	504	2525	1	620	1	18	131	0	41	414
10/30/17 3:00 PM	13	255	1000	499	541	2603	1	636	1	18	131	0	36	414
10/30/17 4:00 PM	8	252	674	438	541	2317	1	572	0	18	131	0	29	414
10/30/17 5:00 PM	8	252	326	438	542	2346	2	572	0	18	131	0	29	414
10/30/17 6:00 PM	8	248	247	438	542	2403	2	572	0	18	131	0	29	373
10/30/17 7:00 PM	8	4	274	438	482	2069	2	572	0	18	131	0	15	104
10/30/17 8:00 PM	8	4	111	438	467	2143	2	591	0	18	131	0	15	115
10/30/17 9:00 PM	0	4	136	281	467	1921	2	585	0	18	131	0	16	115
10/30/17 10:00 PM	0	5	136	281	467	1843	2	585	0	18	131	0	16	116
10/30/17 11:00 PM	0	5	136	281	467	1844	2	585	0	18	131	0	16	116
10/31/17 12:00 AM	0	5	136	281	467	1844	2	585	0	18	131	0	16	116
10/31/17 1:00 AM	0	5	136	281	467	1838	2	585	0	18	131	0	16	116
10/31/17 2:00 AM	0	5	136	281	467	1838	2	585	0	18	131	0	16	116
10/31/17 3:00 AM	0	5	136	281	467	1838	2	585	0	18	131	0	16	116
10/31/17 4:00 AM	0	5	136	281	467	1838	2	585	0	18	131	0	16	116
10/31/17 5:00 AM	0	5	136	281	467	1838	2	585	0	18	131	0	16	116
10/31/17 6:00 AM	0	5	136	281	467	1838	2	585	0	18	131	0	16	116
10/31/17 7:00 AM	0	5	136	281	467	1823	2	585	0	18	131	0	16	116
10/31/17 8:00 AM	0	5	136	281	467	1823	2	585	0	18	131	0	16	116
10/31/17 9:00 AM	0	5	136	281	467	1823	2	585	0	18	131	0	16	116
10/31/17 10:00 AM	0	5	136	273	467	983	2	585	0	18	131	0	16	116
10/31/17 11:00 AM	0	5	136	273	467	983	2	561	0	18	131	0	16	116
10/31/17 12:00 PM	0	5	136	273	467	900	2	433	0	18	107	0	16	116
10/31/17 1:00 PM	0	5	136	273	467	730	2	369	0	18	107	0	16	116

	Allenstown	Boscawen	Bow	Canterbury	Chichester	Concord	Dunbarton	Epsom	Hooksett	Hopkinton	Loudon	Pembroke	Salisbury	Webster
10/31/17 2:00 PM	0	5	136	219	445	490	2	126	0	18	107	0	16	116
10/31/17 3:00 PM	0	5	136	219	445	448	2	59	0	0	107	0	16	19
10/31/17 4:00 PM	0	5	136	219	445	365	2	59	0	0	107	0	16	19
10/31/17 5:00 PM	0	5	110	219	305	363	2	49	0	0	96	0	15	18
10/31/17 6:00 PM	0	5	73	184	197	363	2	33	0	0	85	0	0	12
10/31/17 7:00 PM	0	5	71	184	196	336	2	32	0	0	85	0	0	11
10/31/17 8:00 PM	0	4	41	95	153	333	2	18	0	0	85	0	0	0
10/31/17 9:00 PM	0	4	41	88	141	294	1	18	0	0	85	0	0	0
10/31/17 10:00 PM	0	4	29	88	141	294	1	18	0	0	85	0	0	0
10/31/17 11:00 PM	0	4	29	74	141	293	1	18	0	0	85	0	0	0
11/1/17 12:00 AM	0	4	29	74	141	293	1	18	0	0	85	0	0	0
11/1/17 1:00 AM	0	4	29	74	141	293	1	18	0	0	85	0	0	0
11/1/17 2:00 AM	0	4	29	74	141	239	1	18	0	0	85	0	0	0
11/1/17 3:00 AM	0	4	29	74	141	239	1	18	0	0	85	0	0	0
11/1/17 4:00 AM	0	4	29	74	141	238	1	18	0	0	85	0	0	0
11/1/17 5:00 AM	0	4	29	74	141	238	1	18	0	0	85	0	0	0
11/1/17 6:00 AM	0	4	29	74	141	219	1	18	0	0	85	0	0	0
11/1/17 7:00 AM	0	4	29	74	141	218	1	18	0	0	85	0	0	0
11/1/17 8:00 AM	0	4	29	74	141	218	1	18	0	0	85	0	0	0
11/1/17 9:00 AM	0	4	29	74	140	187	1	18	0	0	85	0	0	0
11/1/17 10:00 AM	0	4	13	41	139	166	1	18	0	0	85	0	0	0
11/1/17 11:00 AM	0	4	10	30	139	164	1	18	0	0	85	0	0	0
11/1/17 12:00 PM	0	4	7	28	135	13	1	5	0	0	53	0	0	0
11/1/17 1:00 PM	0	4	6	22	135	13	0	5	0	0	29	0	0	0
11/1/17 2:00 PM	0	4	1	21	135	13	0	5	0	0	29	0	0	0
11/1/17 3:00 PM	0	2	1	21	133	8	0	4	0	0	29	0	0	0
11/1/17 4:00 PM	0	1	1	21	132	6	0	3	0	0	29	0	0	0
11/1/17 5:00 PM	0	1	1	1	130	5	0	3	0	0	25	0	0	0
11/1/17 6:00 PM	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Attachment 5 – UES Customer Hourly Interruptions By Town (Seacoast Region)

	Atkinson	Brentwood	Danville	Derry	East Kingston	Exeter	Greenland	Hampstead	Hampton	Hampton Falls	Kensington	Kingston	Newton	North Hampton	Plaistow	Sandown	Seabrook	South Hampton	Stratham
10/30/2017 0:00	0	0	0	0	0	0	0	0	0	0	0	26	1529	0	86	0	0	188	6
10/30/2017 1:00	240	0	0	0	20	6	0	0	0	294	350	482	1531	0	86	0	2191	319	6
10/30/2017 2:00	1476	35	1133	3	110	2788	0	0	2809	333	350	726	1676	4	952	2	2191	355	1707
10/30/2017 3:00	1567	35	1159	3	165	1269	0	0	2809	333	350	1011	1676	4	999	2	2191	355	656
10/30/2017 4:00	1568	35	1159	3	165	1528	0	0	4631	333	350	1013	1676	4	1006	2	1205	355	88
10/30/2017 5:00	1600	35	1192	3	165	1528	0	0	5498	380	350	1013	1676	4	1058	2	4089	355	296
10/30/2017 6:00	1669	35	1192	3	167	1528	0	0	7487	412	383	1061	1676	4	1058	2	4089	355	332
10/30/2017 7:00	1671	35	1192	3	197	1528	0	0	7365	416	383	1075	1676	4	1058	2	1205	355	562
10/30/2017 8:00	1702	0	1192	3	177	563	0	0	6543	416	384	1003	1684	4	1058	2	1205	355	587
10/30/2017 9:00	1671	0	33	3	233	386	0	0	6543	416	384	980	1684	4	1058	0	1213	355	587
10/30/2017 10:00	1789	0	33	3	245	386	0	0	5376	420	384	980	1753	4	1058	2	1213	371	587
10/30/2017 11:00	1790	0	59	3	245	386	0	0	5376	420	384	980	1700	4	1058	2	1213	355	587
10/30/2017 12:00	1790	0	59	3	190	638	0	0	3430	420	384	980	1703	0	1058	2	1213	355	1333
10/30/2017 13:00	1790	0	59	3	190	638	0	0	3430	420	384	980	1703	0	1058	2	1213	355	1333
10/30/2017 14:00	1790	0	59	3	190	639	0	0	3430	420	351	980	1703	0	1208	2	1213	355	1333
10/30/2017 15:00	1790	0	59	3	173	639	0	0	3037	420	351	980	1703	0	1208	2	1213	355	1333
10/30/2017 16:00	1793	0	67	3	173	639	0	0	447	420	351	981	1689	0	1209	2	1213	355	1333
10/30/2017 17:00	1793	0	67	3	173	639	0	0	447	159	351	867	1587	0	596	2	446	355	1333
10/30/2017 18:00	1793	0	67	3	173	639	0	0	447	146	1	867	1587	0	596	2	8	225	1333
10/30/2017 19:00	1793	0	67	3	173	639	0	0	447	146	1	867	1587	0	596	2	8	225	1333
10/30/2017 20:00	1769	0	67	3	386	639	0	0	702	146	30	728	1587	0	596	2	8	61	1333
10/30/2017 21:00	1769	0	67	3	386	639	0	0	702	148	30	549	1570	0	596	2	8	134	1333
10/30/2017 22:00	1769	0	67	3	386	639	0	0	703	101	30	549	1584	0	596	2	8	134	1333
10/30/2017 23:00	1769	0	67	3	386	639	0	0	703	148	30	549	1584	0	596	2	8	134	1333
10/31/2017 0:00	1769	0	67	3	386	639	0	0	703	148	30	398	1584	0	596	2	8	134	1333
10/31/2017 1:00	1769	0	67	3	386	639	0	0	613	148	30	398	1584	0	596	2	8	134	1333
10/31/2017 2:00	1720	0	67	3	173	639	0	0	449	148	10	177	1584	0	596	2	8	132	1333
10/31/2017 3:00	1720	0	67	3	173	639	0	0	322	109	10	138	1584	0	596	2	8	132	1333
10/31/2017 4:00	1720	0	67	3	173	639	0	0	322	109	10	138	1584	0	596	2	8	132	1293
10/31/2017 5:00	1720	0	67	3	173	639	0	0	267	109	10	138	1584	0	596	2	8	132	1293
10/31/2017 6:00	1720	0	67	3	173	639	0	0	267	109	10	135	1584	0	596	2	8	132	1293
10/31/2017 7:00	1720	0	67	3	173	619	0	0	267	109	10	135	1584	0	596	2	8	103	1293
10/31/2017 8:00	1720	0	67	3	173	619	0	0	140	109	10	135	1584	0	596	2	8	103	1213
10/31/2017 9:00	1720	0	67	3	173	619	0	0	36	109	10	87	1584	0	596	2	8	103	1085
10/31/2017 10:00	1719	0	39	3	161	605	0	0	36	109	10	30	1584	0	596	2	8	103	1085
10/31/2017 11:00	1719	0	39	3	141	513	0	0	2	78	10	30	1571	0	596	2	8	103	1085
10/31/2017 12:00	483	0	39	3	88	2	0	0	2	78	10	16	56	0	279	2	8	102	27
10/31/2017 13:00	483	0	39	3	34	2	0	0	2	57	10	16	56	0	232	2	8	102	27
10/31/2017 14:00	411	0	39	0	32	2	0	0	2	10	10	16	26	0	81	2	8	22	27
10/31/2017 15:00	365	0	39	0	32	1	0	0	2	10	1	16	11	0	81	2	8	22	27

	Atkinson	Brentwood	Danville	Derry	East Kingston	Exeter	Greenland	Hampstead	Hampton	Hampton Falls	Kensington	Kingston	Newton	North Hampton	Plaistow	Sandown	Seabrook	South Hampton	Stratham
10/31/2017 16:00	365	0	39	0	5	1	0	0	2	10	1	16	9	0	74	0	8	22	27
10/31/2017 17:00	330	0	39	0	5	1	0	0	2	4	1	16	9	0	22	0	8	22	6
10/31/2017 18:00	144	0	13	0	5	1	0	0	2	1	1	16	9	0	15	0	8	22	3
10/31/2017 19:00	144	0	13	0	5	1	0	0	1	1	1	2	2	0	1	0	8	22	3
10/31/2017 20:00	8	0	13	0	5	1	0	0	1	1	0	2	2	0	1	0	8	22	3
10/31/2017 21:00	5	0	13	0	5	0	0	0	1	1	0	2	2	0	1	0	8	22	3
10/31/2017 22:00	5	0	13	0	5	0	0	0	1	1	0	2	0	0	1	0	8	22	3
10/31/2017 23:00	0	0	0	0	5	0	0	0	0	1	0	1	0	0	1	0	8	0	3
11/1/2017 0:00	0	0	0	0	1	0	0	0	0	1	0	1	0	0	1	0	8	0	3
11/1/2017 1:00	0	0	0	0	1	0	0	0	0	1	0	0	0	0	1	0	8	0	3
11/1/2017 2:00	0	0	0	0	1	0	0	0	0	1	0	0	0	0	1	0	8	0	3
11/1/2017 3:00	0	0	0	0	1	0	0	0	0	1	0	0	0	0	1	0	8	0	3
11/1/2017 4:00	0	0	0	0	1	0	0	0	0	1	0	0	0	0	1	0	8	0	3
11/1/2017 5:00	0	0	0	0	1	0	0	0	0	1	0	0	0	0	1	0	8	0	0
11/1/2017 6:00	0	0	0	0	1	0	0	0	0	1	0	0	0	0	1	0	8	0	0
11/1/2017 7:00	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1	0	8	0	0
11/1/2017 8:00	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1	0	8	0	0
11/1/2017 9:00	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11/1/2017 10:00	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11/1/2017 11:00	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11/1/2017 12:00	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11/1/2017 13:00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Attachment 6 – Revised PUC Crew Reports

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
DISTRIBUTION CREW REPORT
(In compliance with Puc 308.14)

EVENT NAME	Wind Event		
DATE REPORT SUBMITTED:	Oct 30 2017	TIME - DATA EXTRACTED:	10:00 AM
Submitted by:	B. LaBelle		
Company:	Unitil Energy Systems		

Quantity of Field Personnel

				Prior to Event[A]	During Event	Incremental
			FRONT LINE			
1	**Distribution** 69 KV and Less includes Subtransmission 46kv, 34.5kv,22kv, 13kv, 7.5 kv, 4kv, 2kv and below	Line	Company Line Crews restoring Distribution Circuits	10	10	0
			Affiliate Co Line Crews restoring Distribution Circuits	0	0	0
			Contractor Line Crews restoring Distribution Circuits	9	19	10
			Foreign Utility Line Crews restoring Distribution Circuits	0	0	0
		Service	Company Line Crews restoring Service	0	0	0
			Contractors restoring Service *includes Electricans*	0	0	0
		Pole[B]	Pole Setting/Digging Operations *includes Co, Foreign Uitlity, Contractor*	2	3	1
		Tree	Contractor Tree Clearing - Working on Distribution Circuits	7	15	8
			Foreign Utility Tree Clearing - Working on Distribution Circuits	0	0	0
			SUBTOTAL	28	47	19
			FIELD ASSESSMENT			
2	Distribution *see above*	Line[C]	Company Damage Assessment Personnel	0	9	9
			SUBTOTAL	0	9	9
			PUBLIC SAFETY			
3	Wires Down Appraiser Field Guides Other Support	Line	Company Personnel	0	18	18
			Bird Dogs, Location Guides	0	0	0
			includes contractors		0	0
			SUBTOTAL	0	18	18

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
DISTRIBUTION CREW REPORT
(In compliance with Puc 308.14)

EVENT NAME	Wind Event		
DATE REPORT SUBMITTED:	Oct 30 2017	TIME - DATA EXTRACTED:	2:00 PM
Submitted by:	M. Gamble		
Company:	Unitil Energy Systems		

Quantity of Field Personnel

					Prior to Event[A]	During Event	Incremental
			FRONT LINE				
1	**Distribution** 69 KV and Less includes Subtransmission 46kv, 34.5kv,22kv, 13kv, 7.5 kv, 4kv, 2kv and below	Line	Company Line Crews restoring Distribution Circuits		10	10	0
		Line	Affiliate Co Line Crews restoring Distribution Circuits		0	0	0
		Line	Contractor Line Crews restoring Distribution Circuits		9	25	16
		Line	Foreign Utility Line Crews restoring Distribution Circuits		0	0	0
		Service	Company Line Crews restoring Service		0	0	0
		Service	Contractors restoring Service *includes Electricans*		0	0	0
		Pole[B]	Pole Setting/Digging Operations *includes Co, Foreign Uitlity, Contractor*		2	3	1
		Tree	Contractor Tree Clearing - Working on Distribution Circuits		7	15	8
		Tree	Foreign Utility Tree Clearing - Working on Distribution Circuits		0	0	0
				SUBTOTAL	28	53	25
			FIELD ASSESSMENT				
2	Distribution *see above*	Line[C]	Company Damage Assessment Personnel		0	9	9
				SUBTOTAL	0	9	9
			PUBLIC SAFETY				
3	Wires Down Appraiser Field Guides Other Support	Line	Company Personnel		0	18	18
		Line	Bird Dogs, Location Guides		0	0	0
		Line	*includes contractors*			0	0
				SUBTOTAL	0	18	18

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
DISTRIBUTION CREW REPORT
(In compliance with Puc 308.14)

EVENT NAME	Wind Event		
DATE REPORT SUBMITTED:	Oct 30 2017	TIME - DATA EXTRACTED:	8:00 PM
Submitted by:	B. LaBelle		
Company:	Unitil Energy Systems		

Quantity of Field Personnel

				Prior to Event[A]	During Event	Incremental
			FRONT LINE			
1	**Distribution** 69 KV and Less includes Subtransmission 46kv, 34.5kv,22kv, 13kv, 7.5 kv, 4kv, 2kv and below	Line	Company Line Crews restoring Distribution Circuits	10	10	0
		Line	Affiliate Co Line Crews restoring Distribution Circuits	0	0	0
		Line	Contractor Line Crews restoring Distribution Circuits	9	50	41
		Line	Foreign Utility Line Crews restoring Distribution Circuits	0	0	0
		Service	Company Line Crews restoring Service	0	0	0
		Service	Contractors restoring Service *includes Electricans*	0	0	0
		Pole[B]	Pole Setting/Digging Operations *includes Co, Foreign Uitlity, Contractor*	2	5	3
		Tree	Contractor Tree Clearing - Working on Distribution Circuits	7	15	8
		Tree	Foreign Utility Tree Clearing - Working on Distribution Circuits	0	0	0
			SUBTOTAL	28	80	52
			FIELD ASSESSMENT			
2	Distribution *see above*	Line[C]	Company Damage Assessment Personnel	0	9	9
			SUBTOTAL	0	9	9
			PUBLIC SAFETY			
3	Wires Down Appraiser Field Guides Other Support	Line	Company Personnel	0	18	18
		Line	Bird Dogs, Location Guides	0	0	0
		Line	*includes contractors*		0	0
			SUBTOTAL	0	18	18

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
DISTRIBUTION CREW REPORT
(In compliance with Puc 308.14)

EVENT NAME	Wind Event		
DATE REPORT SUBMITTED:	Oct 31 2017	TIME - DATA EXTRACTED:	6:00 AM
Submitted by:	B. LaBelle		
Company:	Unitil Energy Systems		

Quantity of Field Personnel

				Prior to Event[A]	During Event	Incremental
			FRONT LINE			
1	**Distribution** 69 KV and Less includes Subtransmission 46kv, 34.5kv, 22kv, 13kv, 7.5 kv, 4kv, 2kv and below	Line	Company Line Crews restoring Distribution Circuits	10	12	2
			Affiliate Co Line Crews restoring Distribution Circuits	0	0	0
			Contractor Line Crews restoring Distribution Circuits	9	50	41
			Foreign Utility Line Crews restoring Distribution Circuits	0	0	0
		Service	Company Line Crews restoring Service	0	0	0
			Contractors restoring Service *includes Electricians*	0	0	0
		Pole[B]	Pole Setting/Digging Operations *includes Co, Foreign Uitlity, Contractor*	2	5	3
		Tree	Contractor Tree Clearing - Working on Distribution Circuits	7	15	8
			Foreign Utility Tree Clearing - Working on Distribution Circuits	0	0	0
			SUBTOTAL	28	82	54
			FIELD ASSESSMENT			
2	Distribution *see above*	Line[C]	Company Damage Assessment Personnel	0	9	9
			SUBTOTAL	0	9	9
			PUBLIC SAFETY			
3	Wires Down Appraiser Field Guides Other Support	Line	Company Personnel	0	18	18
			Bird Dogs, Location Guides	0	0	0
			includes contractors		0	0
			SUBTOTAL	0	18	18

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
DISTRIBUTION CREW REPORT
(In compliance with Puc 308.14)

EVENT NAME	Wind Event		
DATE REPORT SUBMITTED:	Oct 31 2017	TIME - DATA EXTRACTED:	10:00 AM
Submitted by:	B. LaBelle/M. Gamble		
Company:	Unitil Energy Systems		

Quantity of Field Personnel

#	Category	Type	Description	Prior to Event[A]	During Event	Incremental
			FRONT LINE			
1	**Distribution** 69 KV and Less includes Subtransmission 46kv, 34.5kv,22kv, 13kv, 7.5 kv, 4kv, 2kv and below	Line	Company Line Crews restoring Distribution Circuits	10	12	2
		Line	Affiliate Co Line Crews restoring Distribution Circuits	0	0	0
		Line	Contractor Line Crews restoring Distribution Circuits	9	50	41
		Line	Foreign Utility Line Crews restoring Distribution Circuits	0	0	0
		Service	Company Line Crews restoring Service	0	0	0
		Service	Contractors restoring Service *includes Electricans*	0	0	0
		Pole[B]	Pole Setting/Digging Operations *includes Co, Foreign Uitlity, Contractor*	2	5	3
		Tree	Contractor Tree Clearing - Working on Distribution Circuits	7	15	8
		Tree	Foreign Utility Tree Clearing - Working on Distribution Circuits	0	0	0
			SUBTOTAL	28	82	54
			FIELD ASSESSMENT			
2	Distribution *see above*	Line[C]	Company Damage Assessment Personnel	0	9	9
			SUBTOTAL	0	9	9
			PUBLIC SAFETY			
3	Wires Down Appraiser Field Guides Other Support	Line	Company Personnel	0	18	18
			Bird Dogs, Location Guides	0	0	0
			includes contractors		0	0
			SUBTOTAL	0	18	18

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION
DISTRIBUTION CREW REPORT
(In compliance with Puc 308.14)

EVENT NAME	Wind Event		
DATE REPORT SUBMITTED:	Oct 31 2017	TIME - DATA EXTRACTED:	2:00 PM
Submitted by:	C. Brinson		
Company:	Unitil Energy Systems		

Quantity of Field Personnel

				Prior to Event[A]	During Event	Incremental
			FRONT LINE			
1	**Distribution** 69 KV and Less includes Subtransmission 46kv, 34.5kv, 22kv, 13kv, 7.5 kv, 4kv, 2kv and below	Line	Company Line Crews restoring Distribution Circuits	10	12	2
		Line	Affiliate Co Line Crews restoring Distribution Circuits	0	0	0
		Line	Contractor Line Crews restoring Distribution Circuits	9	50	41
		Line	Foreign Utility Line Crews restoring Distribution Circuits	0	0	0
		Service	Company Line Crews restoring Service	0	0	0
		Service	Contractors restoring Service *includes Electricans*	0	0	0
		Pole[B]	Pole Setting/Digging Operations *includes Co, Foreign Uitlity, Contractor*	2	5	3
		Tree	Contractor Tree Clearing - Working on Distribution Circuits	7	15	8
		Tree	Foreign Utility Tree Clearing - Working on Distribution Circuits	0	0	0
			SUBTOTAL	28	82	54
			FIELD ASSESSMENT			
2	Distribution *see above*	Line[C]	Company Damage Assessment Personnel	0	9	9
			SUBTOTAL	0	9	9
			PUBLIC SAFETY			
3	Wires Down Appraiser Field Guides Other Support	Line	Company Personnel	0	18	18
		Line	Bird Dogs, Location Guides	0	0	0
		Line	*includes contractors*		0	0
			SUBTOTAL	0	18	18