UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jersey Central Power & Light Company, PJM Interconnection, L.L.C.	Docket No. ER17-217-000

INDICATED INTERVENORS' PROTEST OF JERSEY CENTRAL POWER & LIGHT'S APPLICATION FOR A FORMULA TRANSMISSION RATE

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Pursuant to Rule 211 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.211 and the Commission's Combined Notice of Filings issued October 28, 2016, Indicated Intervenors[1] submit this Joint Protest of the October 28, 2016 filing by Jersey Central Power & Light ("JCP&L") to establish a formula rate, which formula rate proposes to increase the charges in 2017 in the JCP&L zone of PJM Interconnection, L.L.C. ("PJM") by approximately 150% of the 2016 charges.[2] As explained below, the Commission should suspend JCP&L's proposed formula rate for five months, establish a refund effective date, and set this proceeding for a hearing to be held in abeyance pending the outcome of settlement discussions to be held under the auspices of a Commission Administrative Law Judge.

I. INTRODUCTION

In the limited time since JCP&L made its rate filing, Indicated Intervenors have identified many flaws in JCP&L's proposed formula rate because JCP&L has not complied with Commission precedent. JCP&L's failure to comply with Commission

[1] Indicated Intervenors are: New Jersey Division of Rate Counsel; New Jersey Board of Public Utilities; Public Power Association of New Jersey; and U.S. Department of Defense/Federal Executive Agencies. Each of the Indicated Intervenors has separately and timely moved to intervene in these proceedings.

[2] Jersey Central Power & Light Co., Formula Rate Filing (Oct. 28, 2016), eLibrary No. 20161028-5151 ("Rate Filing").

precedent has resulted in a proposed formula rate that is unjust and unreasonable and that, using JCP&L's projected 2017 year-end data, produces substantially excessive transmission charges. Below, we address the following flaws identified to date which have substantially increased the proposed rate:

- Excessive return on equity ("ROE"), section II.A, which inflates the 2017 proposed rate by about $955/MW-Year;
- Recovery of out-of-period vegetation management costs, section II.C, which inflates the 2017 proposed rate by about $340/MW-Year;
- Recovery of out-of-period regulatory costs, section II.D, which inflates the 2017 proposed rate by almost $185/MW-Year; and,
- Failure to use a labor allocator to functionalize General and Intangible Plant, section II.E, which inflates the 2017 proposed rate by over $795/MW-Year.

Correcting each of these flaws would reduce the proposed 2017 rate by over $2,200/MW-Year. Because JCP&L's proposed 2017 rate reflects an increase of $8,120.10/MW-Year, Indicated Intervenors' analysis demonstrates that much more than 10% of the proposed increase is excessive. The Commission should suspend the proposed rate for the maximum five-month period.

In addition to the issues listed above which have an immediate rate impact, Indicated Intervenors explain at section II.B that JCP&L's proposed recovery of storm costs is excessive. The Commission must not permit JCP&L to unreasonably delay rate filings and substantially prejudice ratepayers. Indicated Intervenors also identify at section II.I several significant respects in which JCP&L's proposed protocols do not conform to the Commission's recent orders establishing standards for formula rate protocols. Finally, Indicated Intervenors have identified numerous other locations in the proposed formula rate at which unsupported numerical data is entered, rendering the formula insufficiently transparent (section II.H). Indicated Intervenors require more time and the opportunity to obtain more information to fully review the rate and identify other areas of the filing, such as proposed new depreciation rates (section II.F), which may not be just and reasonable.

II. JCP&L'S PROPOSED FORMULA RATE WILL YIELD RATES THAT ARE SUBSTANTIALLY EXCESSIVE AND ARE UNJUST AND UNREASONABLE

A. JCP&L's requested ROE is substantially excessive.

JCP&L requests a base Return on Equity ("Base ROE") of 10.5%, along with a 50 basis point "incentive" adder for its participation in a regional transmission organization. As explained below, JCP&L's proposed Base ROE has been calculated in a manner contrary to the Commission's most recent precedent on this subject. Following that precedent and making all assumptions in favor of JCP&L, the properly calculated Base ROE for JCP&L is no higher than 8.7%. And, while Indicated Intervenors do not oppose JCP&L's requested RTO participation adder, the combination of the Base ROE and any incentive adders cannot exceed 9.6%, which is the top of the range of reasonableness calculated using a properly-screened proxy group. Accordingly, JCP&L's requested ROE is substantially excessive and is unjust and unreasonable.

1. The Commission's recent precedent on ROE determination.

For purposes of this Protest, we adopt the following as what we submit is a current and generous-to-JCP&L statement[3] of Commission policy and precedent governing the setting of an allowed Base ROE and maximum allowed incentive Return on Equity ("Ceiling ROE") in the context of a transmission formula rate for an individual utility (the "subject utility"), such as that proposed by JCP&L here:

a. The range of possible Base ROEs, and the Ceiling ROE, are both defined by a two-stage Discounted Cash Flow ("DCF") study of appropriate risk-comparable publicly-traded U.S. utility parent companies, using a DCF study period of six appropriately-timed calendar months.[4]

b. To be an acceptable proxy, each company must meet at least the following criteria.

b.1. It owns, or is, a U.S. electric utility.[5]

b.2. Its stock is publicly traded.[6]

b.3. As a measure of risk comparability, its issuer credit rating from both Standard & Poor's and Moody's (or from either of them if it

[3] Key elements of this restatement remain subject to arguable interpretation, rehearing, or judicial review, and/or should be treated as case-specific factual rulings but have lately been treated as if they were settled rulings of law. On these and other grounds, Indicated Intervenors expressly retain their rights to assert at subsequent stages of this proceeding that this restatement is not the law, should be reconsidered and/or should not be applied to JCP&L in particular. It is unnecessary to argue about the elements now, however, because even assuming for the sake of argument that they apply, it is clear that the 10.5% Base ROE sought by JCP&L has not been supported by studies consistent with even this shareholder-favoring statement of Commission policy.

[4] *See Coakley v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234, PP 8, 17 ("Opinion 531"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) ("Opinion 531-A"), *order on reh'g*, 150 FERC ¶ 61,165 (2015) ("Opinion 531-B"), *appeal pending*.

[5] *Id.* PP 93, 96

[6] *S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 179 (D.C. Cir. 2013) ("*SCE*").

has only one such rating) is within one "notch" of each of these agencies' issuer credit ratings for the subject utility.[7]

b.4. It is covered by Value Line's standard-format quarterly report on each major U.S. utility stock, thereby demonstrating that it is relied on by the investment community.[8]

b.5. The company did not cut its dividend during or shortly before the study period.[9]

b.6. The company is not, during the DCF study period, engaged in a merger or comparable transaction sufficiently significant to distort its stock price or other DCF inputs.[10]

c. An implied cost of equity ("ICOE") is calculated for each such proxy using the following formula and definitions.

c.1. ICOE = Growth ("*g*") + Adjusted Dividend Yield ("ADY")[11], where:

c.1.1. *g* =((2 x IBES Growth) + GDP Growth)/3,[12] where (i) IBES Growth = the consensus of investment analysts' currently-projected three-to-five-year earnings growth rate, as aggregated by IBES (a database formerly known as the Institutional Brokers' Estimate System, and now maintained by Thomson Reuters) or, *if* IBES data is not available, a comparable aggregator of investment analysts'

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[7] Opinion 531, P 107.

[8] *Id.* PP 89 n.164, 100.

[9] *Id.* P 112.

[10] *Id.* P 114.

[11] *Id.* PP 15, 17, 25.

[12] *Id*.

consensus estimate;[13] (ii) GDP Growth = forecast nominal (i.e., non-constant-dollar) growth of the U.S. Gross Domestic Product over a long-term (50-year) forecast horizon, derived from the average of Energy Information Administration, Social Security Administration, and IHS Global Insight projections.[14]

c.1.2. ADY = Raw DY * (1+*g*/2), where Raw DY = average over six study months of each monthly past dividend yield, calculated for each proxy stock each month, as the most recent dividend declared as of that month,[15] divided by the average of that month's high and low trading price,[16] and *g* = the composite growth rate calculated at step c.1.1 above.[17]

d. The range of ICOEs resulting from step c, narrowed if appropriate by excluding outliers that are deemed economically illogical, forms the DCF range.

d.1. The test for whether low outliers are excluded as economically illogical is whether their ICOE exceeds average utility bond yields during the six-month study period by at least 100 basis points, plus or minus a modest adjustment to that margin if warranted by a "natural break" in the ICOE distribution.[18]

d.2. The applicability of any test for economically illogical high outliers, such as an application or update of the former test that

[13] *Id*. PP 39, 90.

[14] *Id.* P 39 n.67.

[15] *Id.* PP 77-78.

[16] *Id*.

[17] *Id.* P 15.

[18] *Id.* PP 122-23.

limited proxy growth to 13.3% and limited ICOEs to 17.7%, remains an open question.[19]

e. The Base ROE for the subject single utility is set at the median of the resulting retained ICOE distribution, subject to step f.[20]

f. If study-period financial market conditions are found to be anomalous, four alternate benchmarks (recent state commission determinations of electric utility returns, and studies using the Capital Asset Pricing Model, risk premium, and expected return on book-value equity) are consulted as checks on the appropriateness of the DCF median. If they point consistently to an ROE substantially exceeding the DCF median, the ROE is set at the median of the upper half of the DCF distribution, i.e., at the distribution's 75th percentile.[21]

g. The Ceiling Return is the top of the DCF range determined at step d.[22]

2. The Commission should rely on the median in a single utility rate case.

The choice of central tendency measures at Steps e and f of the foregoing warrants additional comment, as it is a potentially pivotal issue. The Commission's placement of a Base ROE within a distribution of DCF ICOEs begins with one of two possible measures of central tendency, with the choice between them depending on whether the ROE at issue will apply region-wide or is individual utility-specific. In *SCE*, for example, the Commission distinguished between (a) individual-utility cases, where

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[19] *See id*. P 118. In Opinion 531, the Commission held that adoption of the two-step DCF methodology obviated the need to screen the proxy group for unsustainable growth rates. However, Opinion 531 is under judicial review. *Emera Maine v. FERC*, No. 15-1118 (D.C. Cir. filed Apr. 30, 2015).

[20] *See SCE*, 717 F.3d at 183-87.

[21] *See Ass'n of Buss. Advocating Tariff Equality*, Opinion No. 551, 156 FERC ¶ 61,234, P 276 (2016) ("Opinion 551").

[22] Opinion 531-A, PP 1, 11; Opinion 531-B, PP 139-146.

the laws of statistics support reference to the median, as a central tendency measure that is "less affected by extreme numbers than the midpoint,"[23] which "is clearly subject to distortion by extremely high or low values,"[24] and (b) region-wide ROE cases, where the Commission "must ensure that the base ROE sufficiently supports the entities that have ventured into the [Regional Transmission Organization] membership and that [the base ROE] results in a reasonable rate of return as applied to all the companies in the group."[25]

Here, it is indisputable (and not disputed) that the ROE at issue is for an individual utility, as PJM does not utilize a region-wide ROE, and that JCP&L is therefore filing as a single utility. Indeed, while JCP&L's ROE would not be a region-wide ROE in any event, the individual-utility status of JCP&L's ROE is reinforced by the fact that JCP&L has elected to file its formula rate and ROE separately from its Ohio, Pennsylvania, and West Virginia affiliates, including Mid-Atlantic Interstate Transmission in Pennsylvania, which has filed its formula rate in Docket No. ER17-211. Thus, it is beyond genuine dispute that the applicable measure of central tendency is the median of a properly-structured proxy group.

Under Opinions 531 and 551 (pending appeal), if market conditions are found to be "anomalous," non-DCF measures of the cost of equity are considered, and if those measures demonstrate that it is necessary to place the Base ROE alternative in the upper half of the DCF results, the same form of central tendency measure is utilized in

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[23] *SCE*, 717 F.3d at 182.

[24] *Id.*, 717 F.3d at 184 (quoting *S. Cal Edison Co.*, 131 FERC ¶ 61,020, at 61,145-46 (2010)).

[25] *Id.*, 717 F.3d at 185 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020, at 61,146). *See also* Opinion 551, P 276 (the Commission "us[es] the midpoint of the ROEs in a proxy group when establishing a central tendency for a region-wide group of utilities"); Opinion 531, P 144 ("the Commission has previously found the midpoint of the zone of reasonableness to be the appropriate measure of central tendency for determining the base ROE for a diverse group of utilities (as opposed to the median, used for a single utility)").

identifying the appropriate placement within the upper half. That is, "the Commission has traditionally used measures of central tendency to determine an appropriate return in ROE cases and, in cases involving the placement of the base ROE above the central tendency of the zone of reasonableness, the Commission has used the central tendency of the top half of the zone."[26] As that case concerned a region-wide ROE case, the Commission used the midpoint halfway between the midpoint and the top of the DCF range—as it were, the midpoint's midpoint—that being the measure within the upper half that was "consistent with the Commission's established policy" for identifying the central tendency of the full distribution.[27] Here, in an individual-utility case, if the central tendency of the entire distribution is found to be insufficient, then consistent application of the same policy would point toward the median of those DCF ICOEs that are distributed between (or at) the median and the top of the DCF range—as it were, the median's median—as being the measure within the upper half that would be "consistent with the Commission's established policy" for identifying the central tendency of the full distribution in an individual-utility case. Another name for the median of the upper distribution is the 75th percentile—in a hypothetical distribution of 100 ICOEs, the point that exceeds 75 of the ICOEs, and is exceeded by 25 of the ICOEs.

3. JCP&L has not properly applied the Commission's policy.

Proper application of the foregoing summary of Commission policy (section II.A.1 above) and use of the 75th percentile (section II.A.2 above) to JCP&L's own DCF

[26] Opinion 551, P 276.

[27] *Id*. *See also* Brief of Respondent Federal Energy Regulatory Commission at 69, *Emera Maine v. FERC*, No. 15-1118 (D.C. Cir. filed Apr. 30, 2015) (characterizing the Opinion 531 decision to use the upper midpoint as "consistent with the Commission's established policy of using the midpoint when establishing a central tendency for a region-wide group of utilities").

calculations[28] makes clear that JCP&L's requested 10.5% Base ROE and 11.0% Ceiling ROE are substantially excessive.

First, the proxy group composition policies summarized above preclude expanding the proxy group to encompass utilities with a two-notch, rather than one-notch, credit rating difference from JCP&L. Moreover, JCP&L's argument for "relaxing" the one-notch rule—that "a limited group of companies increases the potential for error . . . analogous[ly] to the use of sampling in statistical analyses"[29] is patently inconsistent with its attempt to set aside "the laws of statistics"[30] in order to emphasize the single high-outlier proxy (Avangrid) that such expansion would add. Consequently, JCP&L's "Expanded Group," JCP-12 at 2, must be rejected. We will therefore focus on JCP&L's first set of DCF results, JCP-12 at 1.

Second, even if Avangrid passed the "one notch" test for proxy group eligibility, it would be disqualified because less than 20% of its stock is publicly traded—the lion's share, 81.5%, being held by its parent, Iberdrola, S.A.[31] As a consequence, Value Line

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[28] JCP&L's DCF study period was March–August 2016. *See* IBES-Based DCF Model at 1 note (a), Exhibit JCP-12 of Rate Filing ("JCP-12"). Updating the study would likely produce *lower* results than those presented by JCP&L and discussed here, because the IBES growth rate for Black Hills Corp. (which should form the top of the DCF range as of March–August 2016, as will be shown) has declined substantially since August 2016. Compare the 7.9% growth rate for Black Hills Corp. as of September 8, 2016 (JPC-12 at 1, row 3, column (d)) with the current IBES growth rate of 6.7%. Attached hereto as Ex. 1 is a 3-page printout from Reuters, available at http://www.reuters.com/finance/stocks/analyst?symbol=BKH. Also attached hereto as Ex. 2 is a 2-page printout from Yahoo! Finance, available at https://finance.yahoo.com/quote/BKH/analysts?p=BKH. The substantially lower, 6.70% growth rate for Black Hills is highlighted at page 2 of the Reuters printout and page 2 of the Yahoo! Finance printout.

[29] Direct Testimony and Exhibits of Adrien M. McKenzie, CFA at 22:4-6, Exhibit JCP-8 of Rate Filing ("JCP-8").

[30] *SCE*, 717 F.3d at 184 (quoting *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at 61,145-46, and *Nw. Pipeline Corp.*, 99 FERC ¶ 61,305, at 62,276 (2002)).

[31] *See* Avangrid, Inc., Quarterly Report at 10 (Form 10-Q) (Nov. 4, 2016), http://www.avangrid.com/InvestorRelations/secfilings.html ("AVANGRID is an 81.5% owned subsidiary of Iberdrola, S.A. (Iberdrola), a corporation organized under the laws of the Kingdom of Spain. The

does not include Avangrid in its quarterly, standard-format, company-specific reports on U.S. utility stocks of significant interest to individual investors. The Commission's established proxy group criteria require such Value Line coverage.[32] They do so for good reason: when stocks go uncovered by Value Line's standard reports, it is because they are unusual. Value Line's non-coverage of Avangrid explains the unavailability of a Value Line beta for Avangrid to be used in the calculation shown at JCP-14, which does utilize Value Line betas for all other proxies. Here, although Avangrid is a substantial company in terms of customers served by its subsidiary operating companies and the assets they hold, the fact that shareholders other than Iberdrola hold only what amounts to passive, non-voting shares (because the controlling interest held by Iberdrola holds what amounts to the only vote) makes it not comparable to the broadly traded utility stocks that are properly included in a DCF study. "Empirical data 'suggest an average minority discount of between 29-33% off the value of controlling shares.'"[33] Consequently, Iberdrola's controlling interest reduces the market price of the minority Avangrid shares that are in public circulation, raises Avangrid's dividend yield, and upwardly distorts Avangrid's DCF result.

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remaining outstanding shares are publicly traded on the New York Stock Exchange and owned by various shareholders.").

[32] *See* Opinion 551, PP 9, 20 (affirming Presiding Judge's proxy group, which excluded Unitil Corp. for lacking such coverage); Opinion 531, P 89 n.164 (citing with approval "*N. Pass Transmission LLC*, 134 FERC ¶ 61,095 at P 52 (approving proxy selection criteria that required available . . . Value Line data)" and "*Pub. Serv. Elec. & Gas Co.*, 126 FERC ¶ 61,219 at P 62 (approving a screen which excluded companies for which no . . . Value Line data is available).

[33] *See* Douglas K. Moll, *Shareholder Oppression and "Fair Value": of Discounts, Dates, and Dastardly Deeds in the Close Corporation*, 54 DUKE L. J. 293, 315 (2004), http://scholarship.law.duke.edu/cgi/viewcontent.cgi?article=1233&context=dlj (quoting in part John D. Emory, Jr., Comment, *The Role of Discounts in Determining "Fair Value" Under Wisconsin's Dissenters' Rights Statutes: The Case for Discounts*, 1995 WIS. L. REV. 1155, 1161, and citing to similar effect Shannon P. Pratt et al., VALUING SMALL BUSINESSES AND PROFESSIONAL PRACTICES 438 (3d ed. 1998) ("citing empirical data from 1980 to 1996 indicating that minority discounts average between 26 and 33 percent")).

Third, in this individual-utility case, JCP&L's reference to the "Midpoint-Top Half" of the JCP-12 distribution must be rejected. As explained above, under the logic of Opinion 551, P 276, the Base ROE placement decision is a choice between the median of the full distribution and the median of the upper half—hereinafter, the "upper median."[34] In JCP&L's "Initial Group" DCF study, JCP-12 at 1, those figures are 8.19% and 9.25%, respectively.[35] The latter figure is the point that would be indicated by Opinions 531 and 551, as explained by the Commission, in the event market conditions are found to remain anomalous and supplemental measures are found to require a Base ROE placement at the central tendency of the upper half of the DCF results.

Fourth, JCP&L's suggestion that its "Expanded Group" better captures the risk and reward associated with comparable companies does not withstand scrutiny. As filed but without its improper inclusion of Avangrid, the Expanded Group's upper median is 9.23%.[36] The as-filed upper median of JCP&L's "Initial Group" is virtually identical, at 9.25%.[37] That similarity is not surprising, given the similarity of those groups' average S&P and Moody's ratings, Value Line Safety Rank, Financial Strength, and Beta, and

[34] Opinion 531, P 151 n.306, invites consideration of other Base ROE placements, and Indicated Intervenors reserve their rights to do so. However, in order to simplify the issues at this initial-pleadings stage, we focus here on the two most-prominent alternatives: the median and the upper median.

[35] As the "median" is mathematically identical to the 50th percentile, the upper median is mathematically identical to the 75th percentile. Accordingly, we calculate it using the "Percentile.Inc" function of Microsoft Excel. It can be estimated by hand by starting with the full distribution of retained ICOEs, repeatedly discarding the single highest and three lowest ICOEs, until fewer than five ICOEs remain, and then finding (1) if one remains, that ICOE; (2) if two remain, the 3:1 weighted average of the larger and smaller remaining ICOEs; (3) if three remain, the average of the largest and second-largest ICOE; and (4) if four remain, the second-largest remaining ICOE.

[36] *See* JCP-12 at 2, applying the "Percentile.Inc" function of Microsoft Excel to calculate that distribution's 75th percentile.

[37] *See id.* at 1, applying the "Percentile.Inc" function of Microsoft Excel to calculate that distribution's 75th percentile.

Market Cap.[38] At bottom, JCP&L's argument for referencing the Expanded Group is that its result is more reliable *because* it is higher. That logic is both circular and upward-biased.

Fifth, the 8.19% median and 9.25% upper median of the Initial Group actually overstate JCP&L's indicated cost of equity, because they embody an incorrect and inflated calculation of the dividend yield adjustment made to reflect the quarterly payment of dividends. In calculating this adjustment, JCP&L uses only the generally higher, first-stage growth rate.[39] But Commission policy uses the composite growth rate,[40] and rightly so. Because investors view dividend cuts as a sign of significant financial problems, electric utilities typically raise dividends only when they consider them sustainable over the long run, making the composite growth rate the better predictor of near-term dividend yield increases.[41] As adjusted to use the correct adjustment formula

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[38] *Compare* JCP-11 at 2 *with id.* at 1.

[39] *See* JCP-8 at 29.

[40] *See Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 63,027, PP 28-29 & App. B (2015) (applying "K = (D/P) (1+.5 g) + g" formula to calculate each proxy's ICOE, i.e., using the composite growth rate "g" as the dividend yield adjuster), *aff'd*, Opinion 551, P 18; *Trunkline Gas Co*., 90 FERC ¶ 61,017, at 61,112 (2000) ("The future growth rate is estimated *before* the current dividend yield because the current dividend yield is increased somewhat by the future growth rate in order to adjust for the quarterly payment of dividends by the proxy companies. The Commission . . . regards the future dividend growth rate as consisting of *two* components, a short term growth rate and a long term growth rate." (emphasis added)).

[41] *See, e.g.,* Dr. Roger Morin, *New Regulatory Finance, Public Utilities Reports, Inc*., at 284 (2006) "Under normal circumstances, dividend growth rates are not nearly as affected by year-to-year inconsistencies in accounting procedures as are earnings growth rates, and they are not as likely to be distorted by an unusually poor or bad year. Dividend growth is more stable than earnings growth because dividends reflect normalized long-term earnings rather than transitory earnings, because investors value stable dividends, and because companies are reluctant to cut dividends because of the information effect of dividend payments."). The atypical use of the first-stage growth rate in *Seaway Crude Pipeline Co. LLC,* Opinion No. 546, 154 FERC ¶ 61,070 (2016) ("*Seaway*") is the exception that proves the rule. *Seaway* concerned an oil pipeline Master Limited Partnership and applied a DCF proxy group consisting entirely of such partnerships. *See id.* P 169. Because such partnerships, unlike electric utility parent companies, "distribute most available cash to investors," their "near-term dividend growth would be expected to track the near-term earnings growth." *See id.* P 190 (summarizing Seaway's brief).

(1 plus half the composite growth rate, not 1 plus half the first-stage growth rate), the median and upper median of the Initial Group are 8.18% and 9.23%, respectively.

Sixth, the top of the JCP-12 range, and thus the associated Ceiling Return cap on incentives, is 9.63% (as filed) or 9.62% (with the dividend yield adjustment corrected as just discussed).

Seventh, the upper median and Ceiling Return are still lower than discussed above, because Otter Tail Corp., which sets the top of the JCP-12 Initial Group range, lacks a current IBES consensus growth rate. Only one analyst (Paul Ridzon of KeyBanc) now covers Otter Tail,[42] and his reports do not estimate earnings growth beyond a two-year horizon.[43] Thomson Reuters' direct releases of IBES data make clear that Ridzon has not provided a years-ahead earnings growth rate forecast for Otter Tail since May 13, 2013.[44] With Otter Tail properly removed and with the other adjustments discussed above, the median, upper median, and top of JCP-12 are 7.82%, 8.70%, and 9.60%, respectively. Thus, the highest, still just and reasonable, Base ROE that the Commission should permit JCP&L to use in its proposed formula rate is 8.7%.

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[42] *See* Otter Tail Corp., *Analyst List*, http://www.ottertail.com/analyst.cfm (listing Paul Ridzon of Keybanc Capital Markets as Otter Tail's only covering analyst).

[43] Yahoo Finance, *Black Hills Corporation*, Analysts, attached hereto as Ex. 3.

[44] *ENE (Env't Ne.) v. Bangor Hydro-Elec. Co.*, Commission Trial Staff Official Copies of New England Transmission Owners' Exhibits, Ex. S-3, Schedules of Trial Staff Witness Sabina U. Joe at 5 (July 9, 2015), eLibrary No. 20150709-5296. Attached hereto as Ex. 4 is the referenced page of Witness Joe's exhibit. That page is an IBES database report from Thomson Reuters On Demand and the page has been marked to highlight that, on February 9, 2014, applying its freshness policy that "AFTER 180 DAYS OF NOT BEING REVISED, THE ESTIMATE IS REMOVED," IBES excluded from its database what had been a 6% growth estimate for Otter Tail provided on May 12, 2013. If the Commission reviews the many submissions made by Mr. McKenzie or his colleague Dr. William Avera since 2013 that include a purported IBES growth rate for Otter Tail, it will see that it has never changed from 6.0%. Just as a dog that did not bark informed Sherlock Holmes that no stranger had visited a crime-scene stable, the fact that Otter Tail, unique among electric utility proxies, has had the same purported growth rate posted on Yahoo! Finance since 2013 demonstrates that the posting is not an actual IBES growth rate.

In short, notwithstanding JCP&L's efforts to end-run Commission policy as explained in Opinions 531 and 551, that policy and those Opinions dictate a Base ROE and a Ceiling ROE for JCP&L that are both well below those sought in the Company's filing.

To be clear, while the foregoing results are significantly below the two "upper midpoint" placements approved by the Commission for region-wide applicability in Opinions 531 and 551, they are fairly aligned with the single-utility, percentile-based ROE placements found by the Commission in other cases. In Opinion 501, based on a study period July–December 2005, the Commission adopted a median-based ROE of 9.2%, which it adjusted slightly upward to account for what were then modest post-trial treasury yield trends.[45] Continuing that trend to the present period of low yields on ten-year treasuries would indicate an ROE below 8.0%.[46] In a pair of 2012 electric transmission ROE decisions, the Commission reached preliminary findings (which led to settlements and thus stand as issued) in favor of median ROEs of approximately 8.6%.[47] An initial decision pending before the Commission on exceptions recommends a median-based ROE of 9.01%.[48]

As these examples suggest, our DCF-based ROE results fall below those approved as region-wide ROEs in Opinions 531 and 551 not because our results are

[45] *Golden Spread Elec. Coop., Inc. v. Sw. Pub. Serv. Co.*, 115 FERC ¶ 63,043, P 104 (2006) (finding 9.2% median and noting study period dates and study-period average yield on 10-year treasury bonds of 4.4%), *aff'd in relevant part*, Opinion No. 501, 123 FERC ¶ 61,047 (2008) ("Opinion 501").

[46] JCP&L's witness testifies that the recent yield on 10-year treasuries was 1.70%, i.e., 270 basis points lower than in the Opinion 501 study period. JCP-8 at 49, Table JCP-3. If equity costs decline by 50 basis points for every 100 basis points of decline in treasury bond yields, then the 9.2% found in Opinion 501 would trend to 9.2% - (2.7% / 2) = 7.85%.

[47] *Pub. Serv. Co. of New Mexico*, 143 FERC ¶ 61,227 (2013) ("*PNM*") and *Pac. Gas & Elec. Co.*, 141 FERC ¶ 61,168 (2012) ("*PG&E*").

[48] *Entergy Ark., Inc.*, 151 FERC ¶ 63,008 (2015).

inaccurately low, but because DCF medians and upper medians are typically well below DCF upper midpoints. For example, although the upper midpoint of the Opinion 531 Appendix DCF array was 10.57%, and was selected as the resulting regional base ROE "consistent with the Commission's established policy of using the midpoint of the ROEs in a proxy group when establishing a central tendency for a region-wide group of utilities,"[49] the upper median of that same array was 9.84%. The median and upper median results we report above are the expected result of avoiding undue distortion by a single high outlier.

The difference between the 8.7%–9.25% range of upper medians shown above and the 9.84% upper median as of Opinion 531 is likewise unsurprising. The Opinion 531 DCF results arose from a study period of October 2012 through March 2013.[50] Since the record underlying Opinion 531 was compiled, the cost of equity benchmarks referenced by JCP&L have generally declined substantially.

For example, JCP&L's CAPM study relies on the weighted average of IBES-aggregated analysts' forecasts of growth for dividend-paying stocks in the S&P 500 as of September 3, 2016, and reports that broad-based IBES growth as currently standing at 8.9%. [51] The parallel figure as of the predecessor study referenced in Opinion 531 was 10.3%.[52] Thus, forecast corporate earnings growth has generally declined by about 1.4% over the past several years.

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[49] Opinion 531-B, P 55.

[50] *See* Opinion 531, P 64.

[51] *See* JCP-14 at 1, column (b) & note (b).

[52] *See* Opinion 531-B, P 104.

Base ROEs allowed by state commissions have declined too. They are now almost universally below 10%, and typically about 9.5%. In the most recent six months of state commission outcomes collected by JCP&L (covering January through June, 2016), the average allowed base ROE was 9.65%.[53] But that average omits a June 2016 decision by the New York Public Service Commission setting the allowed ROE for New York State Electric & Gas Corporation[54] and Rochester Gas and Electric Corporation at 9.0%.[55] With those two results included, the adjusted average of state commission base ROE allowances for that period would be below 9.5%.

The decline in the upper median from the 9.84% level of the Opinion 531 array to the 8.7%–9.25% range shown above is entirely consistent with the foregoing trends in forecast earnings growth and state commission ROE allowances. JCP&L's suggestion that the 9.39% return found to be insufficient in Opinion No. 531 must be insufficient now,[56] fails to recognize that the cost of equity changes over time. Unlike JCP&L, the Commission also recognizes that the cost of equity changes, which is why it generally insists on setting ROEs by reference to the most recent available financial market information.[57]

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[53] *See* JCP-16 at 1.

[54] Notably, New York State Electric & Gas Corporation is a near neighbor of JCP&L, serving electric customers in southern New York state while JCP&L serves electric customers in nearby northwestern New Jersey.

[55] *See New York State Elec. & Gas, et al.*, Cases Nos.15-E-0283, 15-G-0284, 15-E-0285, and 15-G-0286, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal, slip op. at 3, *available at* http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0283&submit=Search+by+Case+Number ("The allowed rate of return on common equity for all four businesses will be 9.00 percent.").

[56] *See* JCP-8 at 33.

[57] *See, e.g.*, Opinion 531 P 64.

Indicated Intervenors are prepared to demonstrate at a hearing that the median is a better distillation of the proxy group cost of equity than is the upper median, both because financial market conditions as of the DCF study period were not anomalous[58] and a standard DCF style is therefore fully reliable, and because, in any event, a proper application of non-DCF benchmarks is aligned with the DCF median. For example, Indicated Intervenors believe that a CAPM study resembling that of JCP&L's witness, but adjusted to utilize a two-stage, GDP-constrained growth rate (as is required by the logic of Opinion 531-B, P 133) would indicate a CAPM-based cost of equity approximating 8%.[59] To like effect, even without the realistically-required GDP constraint, using as the CAPM-study earnings growth rate the simple-average, first-stage, IBES-based earnings growth rate for JCP&L's non-utility proxies (6.94%[60]) would indicate a CAPM-based cost of equity of 7.9%.[61] Indicated Intervenors are also prepared to demonstrate that ROE placements between the median and the upper median should be considered on a case-by-case basis, and that such consideration also suggests an ROE

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[58] Opinions 531 and 551 imply that low interest rates are anomalous. *But see, e.g.,* Stanley Fischer, *Why Are Interest Rates So Low? Causes and Implications* (Oct. 17, 2016), *available at* https://www.federalreserve.gov/newsevents/speech/fischer20161017a.pdf (remarks by Federal Reserve Vice Chairman at the Economic Club of New York). Vice Chairman Fischer noted that "factors over which the Federal Reserve has little influence—such as technological innovation and demographics—are important factors contributing to both short- and long-term interest rates being so low at present," *id*. at 1, and cited findings indicating "that the equilibrium interest rate—that is, the federal funds rate that will prevail in the longer run, once cyclical and other transitory factors have played out—has fallen," *id*. at 3, such that "the long-run component of the level of the real federal funds rate is currently very low—around 1/4 percent—compared with a pre-2000 average of 2-1/2 percent."

[59] We base this estimate on the median-company result from JCP-14, 9.36%, adjusted by substituting as the projected growth on a broad stock portfolio of 7.38%, i.e., the 2/3 weighted average of the 8.9% single-stage growth used by JCP&L's witness and the 4.35% long-term GDP growth rate, *see* JCP-12 at 3. This adjustment, applied to PSEG as the median stock in that study, indicates an 8.2% cost of equity.

[60] *See* DCF Model – Non-Utility Group, col. d, Exhibit JCP-18 of Rate Filing ("JCP-18").

[61] We base this estimate on the median-company result from JCP-14, 9.36%, adjusted by substituting as the projected growth on a broad stock portfolio of 6.94%, as supported *supra* at note 60.

below the upper median.[62] However, the foregoing demonstration that the upper median is 9.25% as filed, and no higher than 8.7% as corrected, and is bounded by a range top no higher than 9.6%, suffices to demonstrate the substantial excessiveness of JCP&L's filing.

4. JCP&L's requested ROE is substantially excessive and renders the rates produced by the formula rate to be so unjust and unreasonable that the formula rate should receive the maximum suspension.

In *West Texas Utilities Co.*,[63] the Commission found that when 10 percent of a proposed rate increase appeared to be excessive, the rate increase as a whole would be considered "substantially excessive" and would be suspended for five months. Here, the excessiveness of JCP&L's proposed ROE suffices by itself to demonstrate that a five-month suspension is in order. Exhibit 5-A hereto presents an adjusted version of the JCP&L's Rate Filing Period II Statement BK, Exhibit JCP-22, at 1 to 4. The only difference from the as-filed version is that the as-filed base-plus-incentive ROE, "0.1100" at page 4 line 24, has been replaced with 0.0975, and that change then automatically flows through the as-filed Excel worksheet.[64] That is a generous distillation of the foregoing discussion, which actually supports a base-plus-incentive ROE no higher than 0.0920 (0.0870 + 0.0050), and also supports a Ceiling ROE of 0.0960. Even with that generosity towards JCP&L, the adjusted rate increase demonstrates that the as-filed rate

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[62] Because the refutation of JCP&L's myriad non-DCF studies is not necessary at this stage and would require a lengthier presentation than is feasible in the limited time available for submission of protests, we will defer a detailed explanation and supporting analysis of the briefly summarized points stated here.

[63] *W. Tex. Utils. Co.*, 18 FERC ¶ 61,189, at 61,374 (1982) ("*West Texas*").

[64] To their credit, JCP&L counsel promptly provided the undersigned with a live Excel version of JCP&L's Statement BK upon request. That live version was used to generate Ex. 5-A, with only the adjustments discussed in the text and associated labelling.

is excessive by over $955/MW-Year.[65] As explained at section III below, use of a still-generous ROE reduces the proposed increase by more than 10%. That is, JCP&L's propose rate increase is more than 10% excessive, meeting the *West Texas* test.

B. JCP&L cannot wait four years to request recovery of its restoration costs incurred because of Hurricane Sandy but should be deemed to have been recovering costs in its extant rate.

JCP&L seeks here to recover costs that it incurred over four years ago that the Company says were incurred in connection with restoration efforts following Hurricane Sandy.[66] Although JCP&L completed its efforts "within a few days,"[67] JCP&L readily admits that, during the last four years, it made no effort to seek Commission authorization to defer these costs.[68] JCP&L offers no excuses or explanation for its delay, it stated only that it "intended" to make an appropriate rate filing. As explained below, JCP&L's inexcusable delay has prejudiced ratepayers and is inconsistent with Commission precedent. The Commission should therefore reject JCP&L's proposal. To the extent any recovery by JCP&L of its Hurricane Sandy restoration costs is permitted, the Commission should, consistent with past precedent, order the amortization period to have begun November 1, 2012, or other closely proximate date.

In support of its request for regulatory asset treatment of claimed Hurricane Sandy costs, JCP&L Witness Barwood references the Commission's acceptance of a regulatory asset for restoration costs associated with Hurricanes Katrina and Rita.[69] While Ms. Barwood provides no citations, Indicated Intervenors presume Ms. Barwood is

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[65] Ex. 5-A at 1, line 13.

[66] Direct Testimony of Marlene A. Barwood at 7:16-9:2, Exhibit JCP-20 of Rate Filing ("JCP-20").

[67] *Id.* at 7:25.

[68] *Id.* at 8:11-16.

[69] *Id.* at 8:5-8.

referencing the proceedings considering Entergy Services' proposed amendments to its transmission formula rate filed in Docket No. ER10-984 on March 31, 2010.[70] While Entergy's tariff amendment was filed about 4.5 years after Katrina and Rita, it is important to note that Entergy made annual filings reporting its accrual of a regulatory asset beginning in June 2006, a mere 10 months after the two storms.[71] In addition, the rate proceedings in ER10-984 produced an uncontested settlement approved by the Commission.[72] Because the treatment of the costs of Hurricanes Katrina and Rita were approved as a settlement, that approval, together with the rate mechanism established in the settlement, is not precedential for the belatedly-raised Hurricane Sandy restoration costs. Moreover, the recovery of costs of Hurricanes Katrina and Rita was inextricably linked to complicated federal and state action, including the passage of specific legislation by the U.S. Congress and by the affected states together with the issuance of securitized bonds, to finance the extensive reconstruction efforts spread across Louisiana, Mississippi, and Texas.[73] Thus, the Commission's actions with respect to Entergy's recovery of the costs from Hurricanes Katrina and Rita are of no help to JCP&L.

Although Indicated Intervenors oppose any reliance on the Katrina and Rita rate settlement, Indicated Intervenors do agree that it is appropriate to treat Hurricane Sandy costs as a regulatory asset. The remaining questions are, however, (1) over what period should those costs be amortized and (2) when should the amortization period begin. As to the first question, Indicated Intervenors do not contest the six-year amortization period

[70] Entergy Services, Inc., Filing of Amendments to Open Access Transmission Tariff (Mar. 31, 2010), eLibrary No. 20100401-0238 ("ER10-984 Filing Letter").

[71] Entergy Services, Inc., Annual Information Filing, Filing Letter at 2-3 (June 7, 2006), eLibrary No. 20060607-0099.

[72] *Entergy Servs., Inc.*, 133 FERC ¶ 61,189 (2010).

[73] ER10-984 Filing Letter at 2-4.

proposed by JCP&L. As to the second question, Indicated Intervenors rely on Commission precedent which instructs that the amortization period should be deemed to have begun shortly after repairs were completed, i.e., approximately November 1, 2012. Alternatively, Indicated Intervenors urge the Commission to take official notice that on February 22, 2013, a mere four months after Hurricane Sandy, JCP&L filed with the New Jersey Board of Public Utilities ("BPU") in Docket No. AX13030196 for approval to recover its hurricane recovery costs at retail. This Commission should hold JCP&L to the same standard and deem JCP&L to have filed its request to recover transmission-related restoration costs with the Commission no later than February 22, 2013.

This adjustment would be consistent with precedent. In *Virginia Electric & Power Co.*,[74] the Commission deemed the amortization period to have begun shortly after repairs were completed when the utility, VEPCO, failed to timely seek recovery of its costs. In that case, VEPCO suffered a boiler implosion in August 1974,[75] but did not seek to recover these costs in two subsequent rate filings. VEPCO did not seek authorization for rate recovery until its third subsequent rate filing, made in 1978, four years after the event.[76] The Commission rebuked VEPCO for its delay. In doing so, the Commission recognized[77]

> the company's obligation to include the costs in its cost-of-service for ratemaking purposes *as soon after their incurrence as possible*, in order that a decision could be made whether the current body of ratepayers should be charged for their recovery. A regulated company is not permitted to "sit" on costs, delaying their inclusion in the

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[74] *Va. Elec. & Power Co.*, 15 FERC ¶ 61,052, *on reh'g*, 17 FERC ¶ 61,150 (1981).

[75] *Id.* at 61,113.

[76] *Id.*

[77] *Id.* (emphasis added).

> claimed cost-of-service, until it believes the time is auspicious to seek their recovery.

Accordingly, even though VEPCO would only have had an approximation of costs of the boiler repair, the Commission ordered the amortization of costs to begin January 1, 1975, the effective date of VEPCO's first rate filing subsequent to the boiler explosion, and five months after the event.[78] As a result of its delay in seeking cost recovery, VEPCO was permitted to recover approximately 20% of its costs.[79]

As to its Hurricane Sandy costs, JCP&L should have filed to include those costs in rates in November 2012, i.e., after the Company completed restoration efforts. Had JCP&L sought waiver of the notice requirement, a waiver justified by the nature of the costs, JCP&L likely could have begun recovering its costs prior to January 1, 2013. Even if JCP&L had waited until February 22, 2013 and filed with the Commission in parallel with its state filing, JCP&L could have already been recovering prudently incurred restoration costs. As JCP&L has not provided any excuse or explanation for its delay in filing, the Commission should deem the amortization period for the Hurricane Sandy regulatory asset to have begun on November 1, 2012, or no later than February 2013, consistent with JCP&L's BPU filing.

Indicated Intervenors recognize that an amortization period deemed to have begun on November 1, 2012, could be seen as a 2/3 reduction in JCP&L's recovery of its restoration costs. Such an assumption would be wrong. During the last four years, JCP&L had a transmission rate in effect. While that rate was a "black box," the rate was first justified as a cost-based rate. The costs that factored into the development of that

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[78] *Id.*

[79] *Id.*

rate would necessarily have included costs for storm restoration because New Jersey routinely experiences significant storms such as Nor'easters, ice storms, and significant snow fall events that cause substantial damage to transmission facilities. While Hurricane Sandy was a significant storm, JCP&L has provided the Commission no basis to conclude that JCP&L's existing transmission rates were insufficient to compensate JCP&L for the storm damage experienced during the last 4 years. JCP&L's failure to seek recovery of its costs prior to the instant filing is an admission that JCP&L has not under-recovered and that an amortization period beginning November 1, 2012 is not a 2/3 reduction of restoration costs.

Even if an amortization period beginning November 1, 2012 amounts to a significant reduction of JCP&L's restoration costs, such a sanction is appropriate. JCP&L has complete control over when it makes rate filings. Here, by sitting on costs for four years, JCP&L has deprived customers of the opportunity to timely review the prudency of JCP&L's transmission-related storm expenses. (While the New Jersey BPU reviewed JCP&L's state-jurisdictional costs, no regulator has reviewed the transmission-related expenses.) As a result, employees with JCP&L at the time may have moved on, memories have likely faded, and documents may no longer exist. In sum, by deferring its rate case until now, JCP&L has substantially prejudiced customers' review of JCP&L's expenses. In addition, by waiting four years and proposing a six-year amortization period, JCP&L would impose an intergenerational equity injustice. It is unjust and unreasonable for future ratepayers that take transmission service on JCP&L's facilities to pay for restoration costs incurred ten years prior as well as any extraordinary storm costs that may happen in the interim. Accordingly, the Commission should act to encourage utilities to timely file to recover costs. To the extent JCP&L may not recover a portion of its Hurricane Sandy restoration costs, such a sanction is an appropriate response to JCP&L's unreasonable delay in seeking that recovery.

C. JCP&L has not supported its request for a vegetation management regulatory asset.

JCP&L requests inclusion of a $14.2 million regulatory asset for vegetation management based on conclusory assertions that its "program" is consistent with the Commission's 2004 "Policy Statement on Matters Related to Bulk Power System Reliability"[80] and Commission decisions in two prior proceedings considering requests of JCP&L's affiliates.[81] JCP&L further reports that it intends to complete the program by the end of the 2016 calendar year.[82] The Commission should deny JCP&L permission to record and recover this regulatory asset because JCP&L has failed to substantiate its claim. JCP&L's request is nothing more than an attempt to recover out-of-period historic costs in a future rate period.

JCP&L's reliance on the Commission's 2004 Reliability Policy Statement is misplaced. While the Commission did reference surcharges as a possible rate mechanism to assure the recovery of prudently incurred costs, the Commission did not issue utilities a blank check to recover such a surcharge on top of whatever other costs utilities may be recovering in rates. Moreover, the Commission's 2004 Reliability Statement was issued 12 years ago and was spurred by the 2003 Blackout. Importantly, the North American Electric Reliability Council found that the second major cause of the Blackout was that

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[80] *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052, PP 27-28 (2004) ("2004 Reliability Policy Statement"), *supplemented*, 110 FERC ¶ 61,096 (2005).

[81] JCP-20 at 9:3-10:8.

[82] *Id.* at 9:23.

"FirstEnergy FE did not effectively manage vegetation in its transmission line rights-of-way."[83] Subsequently, the Commission released a report that concluded that FirstEnergy's practices were consistent with industry practice.[84] In response to this now-apparent need for enhanced vegetation management, the Commission issued the 2004 Reliability Policy Statement which, among other things, recognized that utilities would need to make an immediate, systemwide, one-time step-up in vegetation management and would need to have an enhanced vegetation management program going forward.[85] But this quantum improvement in vegetation management practices began in *2004*, more than 12 years ago. Indicated Intervenors presume JCP&L took appropriate steps in *2004* to upgrade its vegetation management practices. Put differently, Indicated Intervenors assume that JCP&L has not been imprudently following pre-2003 Blackout practices for more than a decade. Thus, for the last 12 years, by not filing a rate case or seeking any form of rate adjustment, JCP&L admits that its rates have been sufficiently compensatory of all expenses, including the enhanced vegetation management practices that became

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[83] North American Electric Reliability Council, *Technical Analysis of the August 14, 2003, Blackout: What Happened, Why, and What Did We Learn?* at 40 (July 13, 2004) ("NERC Report"). The NERC Report identified the second cause of the 2003 Blackout as follows:

> **Cause 2: FE did not effectively manage vegetation in its transmission line rights-of-way.** The lack of situational awareness resulting from Causes 1a–1e would have allowed a number of system failure modes to go undetected. However, it was the fact that FE allowed trees growing in its 345-kV transmission rights-of-way to encroach within the minimum safe clearances from energized conductors that caused the Chamberlin-Harding, Hanna-Juniper, and Star-South Canton 345-kV line outages. These three tree-related outages triggered the localized cascade of the Cleveland-Akron 138-kV system and the over-loading and tripping of the Sammis-Star line, eventually snowballing into an uncontrolled wide-area cascade. These three lines experienced non-random, common mode failures due to unchecked tree growth. With properly cleared rights-of-way and calm weather, such as existed in Ohio on August 14, the chances of those three lines randomly tripping within 30 minutes is extremely small. Effective vegetation management practices would have avoided this particular sequence of line outages that triggered the blackout.

[84] CN Utility Consulting, *Utility Vegetation Management Final Report* (March 2004).

[85] 2004 Reliability Policy Statement, PP 27-28.

industry standard in 2004. Reliance on the 2004 Reliability Policy Statement is misplaced.

Similarly, JCP&L's reliance on the Commission's 2005 order in *FirstEnergy Service Co.*[86] is of no help. In that proceeding, the Commission did not authorize the recovery of any costs. Before FirstEnergy could recover any cost, FirstEnergy had to make a subsequent filing. In that subsequent proceeding, the Commission and interested parties would necessarily have the opportunity to review the costs to be recovered and to protect against an unjust over-recovery of costs.[87] Moreover, as noted above, the Commission's authorization of FirstEnergy's use of an accounting mechanism followed the 2003 Blackout, which was caused in significant part by FirstEnergy's ineffective vegetation management program.[88] Accordingly, the 2005 *FirstEnergy* proceeding was an entirely appropriate response to an extraordinary and unique circumstance.

Following the establishment of the regulatory asset in *FirstEnergy*, in 2006, the Commission did review the costs proposed to be included as a regulatory asset. In *Midwest Independent Transmission System Operator, Inc*,[89] the Commission modified American Transmission Systems, Inc.'s ("ATSI") *existing formula rate* to permit a vegetation management surcharge.[90] The fact that ATSI had an existing formula rate was important because it allowed customers to track ordinary vegetation management costs that flowed through the formula rate. These ordinary vegetation management costs could

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[86] *FirstEnergy Service Co.*, 110 FERC ¶ 61,230 (2005) ("*FirstEnergy*").

[87] *Id.* P 16.

[88] NERC Report at 40.

[89] *Midwest Indep. Transmission Sys. Operator, Inc.*, 115 FERC ¶ 61,224, *reh'g denied*, 117 FERC ¶ 61,108 (2006).

[90] *Id.* P 1.

then be compared with costs that were part of ATSI's special vegetation management program. As a result, there was a much reduced, if not completely eliminated, chance of double-recovery, i.e., that costs might be recovered through the formula rate and also be included in the surcharge. That the risk of double-recovery was a non-issue is demonstrated by the fact that the most significant protest in the rate case related to prudency, i.e., should some portion of ATSI's expenses be excluded because those expenses were a "catch-up" necessary to compensate for imprudent prior expenditures on vegetation management.[91]

In this case, JCP&L has had a "black box" stated rate. As a stated rate covering all of JCP&L's costs, it is irrefutable that the rate included an amount for vegetation management. Moreover, a utility has complete control over when it files rates. Accordingly, the Commission is entitled to assume, and does assume, that the utility is recovering its costs until it makes a rate filing.[92] As soon as JCP&L believed it was no longer adequately recovering its costs, it had the opportunity to seek a change in rates. That it did not do so until this proceeding, and that JCP&L has sought to recover its going-forward costs beginning on January 1, 2017, are both admissions that the extant rates amply compensate JCP&L for its costs incurred prior to that date. Accordingly, the Commission should not permit JCP&L to shift out-of-period costs forward and recover those costs in this proceeding.

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[91] *Id.* P 28.

[92] *See, e.g., American Elec. Power Serv. Corp.*, 121 FERC ¶ 61,245, P 8 (2007) (denying AEP's request for rehearing of the Commission's five month suspension of AEP's formula rate, the Commission stated, "We are not persuaded that the five- month [sic] suspension will unreasonably harm AEP during its construction program given that AEP chooses when to propose a rate increase and is aware of the potential for a five-month suspension."); *see also S. Cal. Edison Co.*, 116 FERC ¶ 61,099, PP 15, 17 (2006) (discussing the fact that the utility is in control of when it makes its rate filing and has alternative means to timely recover costs).

Even if the Commission were inclined to permit JCP&L to create and recover a regulatory asset for extraordinary vegetation management expenses, JCP&L has not adequately supported its request. Not only is JCP&L a decade late in seeking to recover extraordinary vegetation management costs, it has made no showing that its vegetation management costs incurred in the past few years were extraordinary. JCP&L's sole explanation of its costs is that it "incurred approximately $14.2 million in costs to expand existing rights-of-ways, conduct vertical trimming, and remove danger trees."[93] As an initial matter, costs of expanded rights-of-ways are recovered in transmission plant. JCP&L may not recover plant costs as if it were an operating expense. JCP&L also cites vertical trimming and the removal of danger trees. These are nothing more than generic categories of expenses that are part of the ordinary course of a prudent vegetation management program. As such, JCP&L should be presumed to have recovered these costs through its stated rate. The Commission should not permit JCP&L to cherry pick these prior period expenses and recover them in future rates.

As with Exhibit 5-A discussed above, Indicated Intervenors have modified JCP&L's Period II Statement BK, JCP-22 at 1-4, to remove the out-of-period, vegetation management regulatory asset to create Exhibit 5-B. The only difference from the as-filed version is that page 1, new line 10a, adjusts the "NET REVENUE REQUIREMENT" at line 10 to remove the amortized vegetation management regulatory asset. The calculation of the Adjusted Annual Rate at page 1, line 13 then references the adjusted NET REVENUE REQUIREMENT calculated at line 10a to determine the rate.

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[93] JCP-20 at 9:8-9.

Removing the amortized vegetation management regulatory asset demonstrates that the as-filed rate is excessive by over $340/MW-Year.[94]

D. JCP&L has not supported its request for a formula rate development cost regulatory asset.

JCP&L has sought to include $1.1 million in regulatory costs as a regulatory asset recoverable over the 2017 calendar year. As with storm costs and vegetation management costs discussed above, regulatory costs are standard utility expenses. In other words, JCP&L's extant "black box" rates necessarily incorporate assumptions that JCP&L will incur certain regulatory expenses so long as those rates were in effect. Moreover, JCP&L's regulatory expenses going forward from the date the formula rate goes into effect will, dollar-for-dollar, be recovered in rates. If JCP&L were particularly concerned about its regulatory expenses incurred prior to filing its rate case, it could have filed a formula rate that would have used a lagging test year. Such a lagging test year formula rate would have permitted JCP&L to recover all of its 2016 costs, including regulatory expenses. Instead, JCP&L has availed itself of the option to estimate its going-forward costs and recover those costs in real time. The Commission should not permit JCP&L to avoid the logical consequences of its choices by combining a leading-year formula rate with recovery of lagging, out-of-period regulatory expenses shifted into a future year.

As with Exhibits 5-A and 5-B discussed above, Indicated Intervenors have modified JCP&L's Period II Statement BK, JCP-22 at 1-4, to remove the out-of-period, regulatory expense regulatory asset to create Exhibit 5-C. The only difference from the as-filed version is that page 1, new line 10a, adjusts the "NET REVENUE

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[94] Ex. 5-B at 1, line 13.

REQUIREMENT" at line 10 to remove the regulatory expense regulatory asset. The calculation of the Adjusted Annual Rate at page 1, line 13 then references the adjusted NET REVENUE REQUIREMENT calculated at line 10a to determine the rate. Removing the regulatory expense regulatory asset demonstrates that the as-filed rate is excessive by almost $185/MW-Year.[95]

E. JCP&L must use the Wages & Salaries Allocator for General and Intangible Plant.

JCP&L proposes to use a Gross Plant allocator to functionalize General and Intangible Plant to transmission.[96] JCP&L's use of a Gross Plant allocator is inconsistent with Commission practice. The Commission requires the use of an allocator based on labor costs to allocate General and Intangible Plant. In *Minnesota Power & Light Co.*, the Commission stated:[97]

> On further consideration of this problem we are of the opinion that General Plant, as covered by Accounts 389-399 in the Commission's Uniform System of Accounts for Public Utilities and Licenses, should properly be allocated on the basis of labor costs. These accounts, for the most part, are related to use by employees, not dollars invested in plant. They include such items as office furniture and equipment, transportation vehicles, equipment used in storing materials, such as lockers and shelving, tools, shop and garage equipment, laboratory equipment, power operated equipment used in construction or repair work, communication equipment and miscellaneous equipment such as hospital equipment, kitchen equipment, operator's cottage furnishings, etc. Thus the company's plant ratio allocation method is not reasonable, and we require that labor ratios be used in allocating general plant here and in succeeding cases.

[95] Ex. 5-C at 1, line 13.

[96] Prepared Direct Testimony and Exhibits of Roger D. Ruch at 7:14-15, Exhibit JCP-1 of Rate Filing ("JCP-1").

[97] *Minnesota Power & Light Co.*, Opinion No. 20, 4 FERC ¶ 61,116, at 61,268, *aff'd*, Opinion No. 20-A, 5 FERC ¶ 61,091 (1978) ("Opinion 20-A").

On rehearing, the Commission clarified that use of the labor allocator was not an absolute requirement, but if a utility desires to use a different allocator, the utility must "show that labor ratios are unreasonable in its situation (not merely that its proposed alternative method is reasonable)."[98] While the Commission in *Minnesota Power & Light Co.* referenced only General Plant, the Commission has also been clear that utilities are to use the labor allocator for Intangible Plant as well.[99]

In this proceeding, JCP&L has, without any explanation, unilaterally decided to use a Gross Plant rather than a labor allocator to functionalize its General and Intangible Plant. Because JCP&L has failed to justify its failure to use a labor allocator, the Commission should summarily rule that JCP&L must change its formula rate template to use the labor allocator.

JCP&L's failure to follow Commission requirements in its formula rate has a significant impact on the calculation of JCP&L's revenue requirement because JCP&L has calculated a Gross Plant allocator of over 23% while the wages and salaries (i.e., the "WS") allocator is under 6%. To attempt to quantify this impact, as with Exhibits 5-A, 5-B, and 5-C discussed above, Indicated Intervenors have modified JCP&L's Period II Statement BK, JCP-22 at 1-4, to properly functionalize General & Intangible Plant using the WS allocator. A change to use the WS allocator must be made at page 2, line 4, to properly functionalize the "General & Intangible" contribution to "GROSS PLANT IN SERVICE" and at page 2, line 10, to properly functionalize the "General & Intangible" contribution to "ACCUMULATED DEPRECIATION." The impacts of these changes then flow through the formula rate to reduce JCP&L's Rate Base by nearly $22 million,

[98] Opinion No. 20-A, at 61,150-151.

[99] *See, e.g.*, *Entergy Servs. Inc.*, 143 FERC ¶ 61,120, P 14 & n.34 (2013).

reduce the Gross Revenue Requirement by over $5 million, and reduce the rate by over $795/MW-Year.[100]

F. The formula incorrectly calculates ADIT

As the Commission is aware from numerous recent utility filings, as well as the vigorous protests, answers to protests, and additional rounds of answers,[101] the Internal Revenue Service has been closely scrutinizing the treatment of Accumulated Deferred Income Taxes ("ADIT") in utility formula rates that use projected data to calculate rates. Because JCP&L has sought to implement a projected rate, it must use proper proration and normalization calculations when it determines ADIT. As explained below, JCP&L has failed to do so because its formula contains certain math errors and because it has not correctly implemented calculations. Indicated Intervenors have identified four such errors.

First, in Attachment 5, page 1, line 4, for December 31, 2016 in column [6], Total, the formula in the cell of the live spreadsheet is incorrect. The formula should be "=SUM(E17:G17)-(H17)+(I17)" because the normal balances in Accounts 281, 282, 283, and 255 are "credits or negative" and the normal balance in Account 190 is a "debit or positive."

Second, in Attachment 5, page 1, line 5, for December 31, 2016 in column [6], Total, the formula in the cell of the live spreadsheet is incorrect. The formula should be "=SUM(E18:G18)-(H18)+(I18)" since the normal balances in Accounts 281, 282, 283, and 255 are "credits or negative" and the normal balance in Account 190 is a "debit or positive."

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[100] Ex. 5-D at 1, line 13.

[101] For example, the Commission may review the many pleadings filed in its Docket No. ER14-1831.

Third, in Attachment 5b, page 1, JCP&L's calculation of the prorated amounts for Q1 through Q4 (page 1, columns [2], [4], [6] and [8]) for FERC Account 190 (Excel row 12), FERC Account 282 (Excel row 19) and FERC Account 283 (Excel row 26), uses an end-of-quarter-period factor to perform the calculation of the prorated amounts. If JC&L proposed a "monthly" prorated calculation, it would be appropriate to use an end-of-period factor. But that is not what JCP&L proposes. Rather, JCP&L proposes a quarterly calculation. Therefore, JCP&L should use a mid-quarter factor because the use of an end-of-quarter factor results in a material understatement of the prorated ADIT amounts for the first two months of each quarter. By using the mid-quarter factor, JCP&L will more appropriately reflect the average ADIT during the quarter.

Fourth, in JCP&L's calculation of the Total Normalization to Attachment 5b, (page 2, column [4]), the calculation does not use any normalized or prorated amounts. Instead, the formula references the book value amounts for ADIT and not the prorated amounts. The correct amount in column [4] can be easily calculated by the following formula ([column [2] – column [3]). The balance for Account 190 in column [5] should equal the balance in the "2017 Activity" column for prorated ending 190 in the amount of $7,464,448. The balance on for Account 282 in column [5] should equal the balance in the "2017 Activity" column for prorated ending 282 in the amount of $320,078,878. And the balance on for Account 283 in column [5] should equal the balance in the "2017 Activity" column for prorated ending 283 in the amount of $11,692,312.

Joint Intervenors require more time and opportunity to obtain more information to fully understand JCP&L's proposed ADIT calculations.

G. More time is required to review JCP&L's depreciation rates.

JCP&L's filing includes new depreciation rates together with brief testimony and a study that purports to support those depreciation rates. Depreciation rates and depreciation studies are very complex and data driven. Indicated Intervenors require the opportunity afforded by hearing and settlement procedures to propound discovery and carefully review the proffered information. Accordingly, at this time JCP&L has not demonstrated that this aspect of its formula rate is just and reasonable.

H. JCP&L's formula is insufficiently transparent.

Since JCP&L filed its formula rate, Indicated Intervenors have attempted to review all aspects of the proposed formula rate. As part of the review, we have identified several locations in the formula in which numbers have been entered. There is no witness testimony explaining these numbers. Indicated Intervenors have not identified any other exhibits filed with the proposed formula rate that support the entered numbers. As a result, the proposed formula rate is insufficiently transparent.

To illustrate the concerns that Indicated Intervenors have identified to date, we provide the following table which identifies the location of the input number and briefly identifies our concern. The list is not intended to be exhaustive or to identify all concerns with each identified location.

Attachment	Page and Line Numbers	Item	Description of Issue
H-4A	Page 1 of 5, Line 4 Page 4 of 5, Line 31 Page 5 of 5, Note V	Revenue Credit Acct 456, Other Electric Revenue	Note provides instructions to derive entry value "On Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects." Require source data to verify.
H-4A Attachment 1 – Schedule 1A	Page 1 of 1, Line 2 Note A	Revenue Credit	Value entered has no source data or calculation. Note states "Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of JCP&L's zone during the year used to calculate rates under Attachment H-4A."
H-4A Attachment 1 – Schedule 1A	Page 1 of 1, Line 4 Note B	Annual MWh in JCP&L zones	Note states "Load expressed in MWh consistent with load used for billing under Schedule 1A for the JCP&L zone. Data from RTO settlement systems for the calendar year prior to the rate year." Require source data to verify.
H-4A Attachment 2 – Incentive ROE Calculation	Page 1 of 1, Line 17	Common cost/common stock	Entered value. Note states "Line 17 to include an incentive ROE that is used only to determine the increase in return and incomes taxes associated with a specific increase in ROE. Any actual ROE incentive must be approved by the Commission. Until an ROE incentive is approved, line 17 will reflect the current ROE."
H-4A Attachment 4 – Accumulated Depreciation Calculation	Page 1 of 1, Lines 29 - 41	Reserve for Depreciation of Asset Retirement Costs	Monthly entered values with source of data cited as Company Records. Additional note states "Reference for December balances as would be reported in FERC Form 1."

Attachment	Page and Line Numbers	Item	Description of Issue
H-4A Attachment 5 – ADIT Summary	Page 1 of 1, Columns [2] through [4]	FERC Account adjustments to calculate ADIT	Notes states "Beginning/Ending Average with adjustments for FAS143, FAS106, FAS109, CIACs and normalization to populate Appendix H-4A, page 2, lines 19-23, col. 3 for accounts 281, 282, 283, 190, and 255, respectively." Require source data of adjustments to verify.
H-4A Attachment 5b – ADIT Normalization	Page 1 of 2, Column [1]	Beginning values to FERC accounts	Beginning value of account 190 is an entered value. Source of data not stated. Require source of data to verify. Calculations for beginning values for accounts 282 and 283 include an unreferenced hard-coded value. Require explanation of formula.
H-4A Attachment 5b – ADIT Normalization	Page 1 of 2, Columns [2], [4], [6] and [8]	Quarterly activity to FERC accounts	Source of quarterly activity not stated; entered values only.
H-4A Attachment 6 – PBOP	Page 1 of 1, Lines 3,4, 6 and 8	Total FirstEnergy PBOP expenses; Labor dollars (FirstEnergy); labor (labor not capitalized) current year; PBOP expense in all O&M and A&G accounts for current year	No supporting data or references cited for amounts entered.
H-4A Attachment 9 – Stated-value Inputs	Page 1 of 1, Lines 17 and 18	Total FirstEnergy PBOP expenses; Labor dollars (FirstEnergy)	Same entries as Attachment 6 – PBOP, lines 3 and 4. No supporting data or references cited for amounts entered.

Attachment	Page and Line Numbers	Item	Description of Issue
H-4A Attachment 7	Page 1 of 1, Line 5a	Sales and use taxes	Sales and use taxes are not includable and need to be removed.
H-4A Attachment 7	Page 1 of 1, Lines 4 to 4z	Gross Receipts Tax	Note J on Attachment H-4A, page 5, excludes Gross Receipts Taxes but JCP&L has included a placeholder in Attachment 7 which could permit recovery of Gross Receipts Taxes.
H-4A Attachment 10 – Debt Cost Calculation	Page 1 of 1, Columns (e), (cc), (dd), and (ee)	Long-term debt inputs (multiple)	Values for Net Amount Outstanding *column (e)*, Amount Issued *column (cc)*, (Discount) Premium at Issuance *column (dd)*, and Issuance Expense *column (ee)* are entered values. No supporting reference or data provided. Require source data to verify.
H-4A Attachment 11 – TEC	Page 2 of 2, Column 9	Project Depreciation Expense	Note states "Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-4A, page 3, line 16." No supporting data or references cited for amounts entered.
H-4A Attachment 11a – TEC Cost Support	Page 1&2 of 2 Lines 2a – 2g	Monthly values for Project Gross Plant and Accumulated Depreciation	Entered values only, no supporting reference or data.
H-4A Attachment 15 – Income Tax Adjustments	Page 1 of 1, Line 1	Tax adjustment for Permanent Differences & AFUDC Equity	Entered values only, no supporting reference or data.

I. JCP&L's formula rate protocols are not just and reasonable.

1. JCP&L has provided insufficient time to review and examine its annual update of its projected formula rate.

JCP&L has proposed to publish its implementation of its projected formula rate on or before[102] October 31 of each calendar year. These rates will go into effect two months later on the following January 1. A two-month window is insufficient to review the projected formula rate, challenge it (if necessary), and obtain corrections prior to the rate going into effect. Accordingly, the Commission should require JCP&L to use an earlier publication date consistent with other utilities' use of projected formula rates. For example, JCP&L's sister company, ATSI, has transmission formula rate protocols that require publication of its projected formula rate by September 1.[103] In addition, the ATSI protocols require ATSI to provide significantly more information and explanation about the projected revenue requirement. The protocols require ATSI to provide "information showing (a) each transmission project forecasted to be placed into service in the following Rate Year that is expected to have a direct cost of $1 million or greater, and a breakdown of the projected direct costs of each such project in as much detail as is reasonably available; and (b) purchases of categories of capital equipment . . . aggregating $3 million or greater that are forecasted to enter service during the following Rate Year."[104] The September 1 deadline and additional information provide customers with an opportunity to review the projected revenue requirement before it takes effect.

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[102] JCP&L's use of "before" does not conform to usage of ordinary English. Section II.D of the protocols in Attachment H-4B of the Rate Filing gives JCP&L the opportunity to publish the Projected Transmission Revenue Requirement on the next business day if October 31 falls on a weekend or holiday.

[103] PJM Interconnection, L.L.C., ATSI Formula Rate Implementation Protocols at 2, Attachment H-21B (Jan. 15, 2016), http://www.pjm.com/media/documents/merged-tariffs/oatt.pdf.

[104] *Id.*

JCP&L provides no explanation as to why it cannot conform to the same standards set by its sister company and why JCP&L instead requires such a late publication date. While JCP&L does provide a two page explanation of its internal budgeting process,[105] that process is purely an internal process, and the dates are driven by JCP&L's own convenience. There is no reason that JCP&L cannot accelerate its process to provide customers with timely information about the rates that they will pay in the coming year. Moreover, ATSI appears to be able to work with the same budgetary process and provide information on September 1. The rush to implement JCP&L's projected revenue requirement will undoubtedly lead to errors. While errors can be corrected in the subsequent true-up, that is, at best, a half-measure that may not compensate some customers. JCP&L proposes that, rather than refund customers for overcharges, it will roll such refunds forward. However, such refund will not be returned until the second year after the rate was errantly collected. For example, an error leading to excessive rates in 2017 will be identified in the true-up process that occurs in June of 2018. The refund will be rolled into rates in 2019. As a result, short-term transmission customers and customers taking service that ends in 2018 will be deprived of refunds. Accordingly, the Commission should require JCP&L to advance its processes to enable customers to have a realistic opportunity to review the implementation of the projected transmission revenue requirement.

The lack of sufficient time to review the implementation of the projected transmission revenue requirement can be seen in JCP&L's very first implementation. JPC&L's forecasted rate starting January 1, 2017 is based on a projected rate base of

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[105] JCP-20 at 5:14-7:14.

$748 million. Based on a review of the information provided to the Commission, however, Indicated Intervenors have not been able to identify support for that rate base. Although review of JCP&L's rate base is complicated by the fact that it has not gone through a rate case since 1998 in Docket No. ER97-3189, JCP&L's attempt to comply with the Commission's Statement BK Period II filing requirements by populating the 2017 projected rate template with forecasted transmission plant in service is of little help. The forecasted plant is based on the company's budgeting process,[106] but it fails to include a narrative explanation, workpapers, or excerpts of the budget[107] explaining new plant additions compared to the 2015 Form 1 data. JCP&L's cover letter mentions that the company is embarking upon a program of transmission upgrades called "Energize the Future," but provided no detail or information about what projects are included or expected to be in service in 2017. Also troubling, the values resulting from the budgeting process are inputted in Attachment 3 of the Statement BK for Period II (formula rate populated for 2017) without being tied down to the FERC Form 1 data.[108]

The change in balances between projected 2017 and actual 2015 end-of-year is substantial. The 2015 FERC Form 1 for JPC&L indicates an ending transmission rate base about $200 million less than the rate base requested for the projected 2017 rates,[109]

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[106] "The forecasts used to prepare the statements [JCP&L Witness Barwood is] sponsoring were based on the JCP&L budgeting process." JCP-20 at 5:24-6:1.

[107] 18 C.F.R. § 35.13(d)(5) ("*Work papers.* A utility that files adjusted Period I data or that files Period II data shall submit all work papers relating to such data. The utility shall provide a comprehensive explanation of the bases for the adjustments or estimates and, if such adjustments or estimates are based on a regularly prepared corporate budget, shall include relevant excerpts from such budget.")

[108] Footnote B on Attachment 3 of the Rate Filing underscores the lack of a clear connection between the 2015 Form 1 and the data inputs for the 2017 transmission plant in service, especially in the initial year, stating in full: "Reference for December balances as *would be* reported in FERC Form 1." (Emphasis supplied.)

[109] *Compare* $1.17 billion (JPC&L 2015 FERC Form 1 at 207:58, col. G, end of year transmission rate base) *with* $1.387 billion (JCP-22 at 2:2, col. 5, transmission gross plant in service).

but a review of the PJM website listing authorized reliability transmission projects does not show projects that will close to plant by 2017 year-end that would explain this increase in the rate base.[110] As a result, JCP&L's filing falls short of the Commission's standards,[111] should be set for hearing to review the reasonableness of the rate base, and shows that a minimal two month period before rates go into effect is so insufficient that the rates to go into effect on January 1 are unjust and unreasonable.

In addition to its unexplained projected rate base, JCP&L appears to have only listed and included ADIT amounts on JCP-22, Attachment 5a at 1-6, "Transmission Related" ADIT amounts and has not included any ADIT items related to "Plant related," "Labor related," "Retail related," or "Other related." JCP&L has not explained this omission in its testimony and Indicated Intervenors have not identified any information in the JCP&L workpapers that support the omission. In general, utilities have numerous ADIT items related to different types of costs, for example, payroll and plant. A review of JCP&L's 2015 FERC Form 1 shows that JCP&L is no exception from this general rule. JCP&L's 2015 Form 1 shows, for example, that its Account 282 contains approximately $1.4 billion. In contrast, JCP&L's formula shows only $315 million for Account 282 related to transmission.[112] There is no additional detail in the filing or FERC Form 1 that explain the $1.1 billion of unaccounted for Account 282 ADIT rate base deduction. JCP&L should be directed to provide enough detail on items excluded from the totals included in the ADIT accounts for interested parties to review.

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[110] *See* PJM Interconnection, L.L.C., *Transmission Construction Status*, http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx.

[111] *See* 18 C.F.R. § 35.13(d)(2); *see also* 18 C.F.R. § 35.13(h)(36)(i)(A) ("The total electric rate base and cost of service shall be itemized and summarized by major functions and in a format designed to facilitate review and analysis.").

[112] JCP-22, Att. 5a at 3.

Similarly, JCP&L's 2017 Operations and Maintenance ("O&M") projections fail to include any costs for Account 565 – Transmission of Electricity by Others, even though the JCP&L 2015 FERC Form 1 shows expenses in Account 565. This omission is important because Account 565 costs are included in the Total Transmission O&M expense cited by the Company as coming from the Form 1 at 321, line 112, and then the formula operates to remove those Account 565 costs from total O&M. By not forecasting any Account 565 costs, the total Transmission O&M expense is overstated because Account 565 costs are forecasted to be zero and therefore not removed from total O&M. That is, JCP&L may significantly over-recover projected transmission O&M expenses. The Company provides no explanation in the filing of why no expenses for this account were included in the 2017 projections.

A final significant hole in JCP&L's forecasted December 31, 2017 data is its forecast of Account 566 – Miscellaneous Transmission Expense in 2017 at a (negative) $7.9 million. In contrast, the amount included in the 2015 JCP&L Form 1 for Account 566 was a *positive* $679,000. The Company has included no support or testimony in its filing that would explain, much less support, a negative $7.9 million cost for Account 566. It is unclear what impact the unsupported, unexplained amount for Account 566 will have on the transmission rate.

These identified concerns with rate base and Account 565 and 566 amounts are particularly unusual and thus standout. Even though Indicated Intervenors quickly identified these issues—issues that may very likely require adjustment to the projected formula rate—it seems doubtful that needed corrections could be implemented in time should the rates be put into effect January 1, 2017. Moreover, discovery will be necessary to fully assess the Company's proposed implementation of 2017 rates. The identified issues merely illustrate that the Commission should require JCP&L to provide more time, consistent with the protocols of its sister company ATSI.

2. The Commission should summarily reject JCP&L's request for single-issue ratemaking.

Contrary to long-standing Commission precedent that generally prohibits single-issue rate filings except in very rare circumstances, JCP&L has asserted a right in its formula rate protocols to make single-issue Federal Power Act ("FPA") Section 205 filings to change depreciation rates or amortization periods, the stated charge for post-employment benefits other than pensions ("PBOPs"), and the weighting of the ADIT in rate base to comply with tax requirements.[113] For the reasons explained below, the Commission should require JCP&L to strike this provision from its formula rate protocols.

The Commission has good reason to generally prohibit single-issue filings. An applicant seeking a change in rates must demonstrate that the *entire* rate is just and reasonable, not just the changed portion of the rate. For example, in explaining the Commission's authority under Section 4 of the Natural Gas Act ("NGA"),[114] the United States Court of Appeals for the Tenth Circuit stated that "[b]y filing the rate increase, a gas company assumes the risk of having to justify its entire rate structure . . . including

[113] Rate Filing, Att. H-4B, JCP&L Formula Rate Implementation Protocols, § IV.I. *See also*, JCP-1 at 17:8-12. Confusingly, JCP&L testimony uses the phrase "such as" before specifying the list of possible single-issue filings which suggests the list is not limited. Because the JCP&L formula rate protocols do not include the "such as," the protocols must control and the list must be strictly limited to the three identified items. This confusion will be mooted by the Commission's rejection of JCP&L's attempt to award itself the authority to make single-issue filings as explained in this section of Indicated Intervenors' protest.

[114] The Commission's authority under the NGA is similar to that in Section 205 of the FPA, 16 U.S.C. § 824d. *See, e.g.*, *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348, 353 (1956).

integral provisions of that structure which the company does not propose to change."[115] Similarly, in *Northern Border Pipeline Co.*,[116] the Commission stated:

> [E]ach component of the pipeline's cost of service is an integral part of the pipeline's proposed overall rate increase. Therefore, the pipeline's burden under NGA section 4 of "showing that an increased rate or charge is just and reasonable" necessarily includes the burden of supporting each component of the cost of service, the unchanged as well as the changed components.

JCP&L's transmission formula rate is no different. While the depreciation and amortization rates, PBOPs, and proper treatment of ADIT are very important formula rate components, the remainder of the formula rate, which factors in all of JCP&L's costs, is equally important. All of the elements which JCP&L would enable itself to change in single-issue filings operate together with the rest of the formula to establish the charges to customers, which charges must be just and reasonable as required by FPA Section 205. Interested parties must have the right to protest a change to an element of the formula rate by identifying related elements or by pointing out that JCP&L has cherry picked certain elements. If interested parties stray beyond the scope of the rate filing, JCP&L is free to challenge such efforts and the Commission is, of course, free to resolve such disputes. The Commission should not now, however, jump to the conclusion that a protest of a hypothetical rate filing will improperly go beyond the scope. Accordingly, the Commission should require JCP&L to strike the language in its protocols which improperly provide JCP&L with authority to make a single-issue rate filing.

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[115] *Colo. Interstate Gas Co. v. FERC*, 791 F.2d 803, 807 (10th Cir. 1986) (citations omitted), *cert. denied*, 479 U.S. 1043 (1987).

[116] *N. Border Pipeline Co.*, 89 FERC ¶ 61,185, at 61,575 (1999).

JCP&L has cited paragraph 109 of the Commission's decision in *South Central MCN LLC*[117] as a case in which the Commission has permitted such single-issue filings. JCP&L's reliance is misplaced. It is true that South Central MCN sought similar single-issue filing rights as JCP&L seeks. No party protested this aspect of the South Central MCN filing and the Commission's order does not acknowledge that deviation from precedent prohibiting single-issue filings.[118] However, in *South Central MCN*, the Commission did reiterate its precedent that utilities seeking a formula rate must conform with the protocols adopted for use by transmission owners in the Midcontinent Independent System Operator ("MISO") or show cause why they should not be required to do so.[119] Given the absence of protest by intervenors and the Commission's silence with respect to single-issue filings, it must be assumed that South Central MCN made a sufficient showing. In contrast, JCP&L has failed to make any showing as to why it should not be required to conform to the Commission's precedent establishing the MISO protocols and Indicated Intervenors have protested JCP&L's claims. Accordingly, the Commission should require JCP&L to strike the language from its protocols.

It is revealing to compare those circumstances in which the Commission has authorized single-issue ratemaking to a potential JCP&L filing to change any of the listed single elements of its formula rate. In Order 679,[120] the Commission first noted that it "typically require[s] a utility seeking a rate increase to expose all of its costs to review

[117] *S. Cent. MCN LLC*, 153 FERC ¶ 61,099 (2015), *reh'g denied*, 154 FERC ¶ 61,271 (2016).

[118] *Id.* PP 109-112.

[119] *Id.* P 111.

[120] *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294, 43,297 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222, P 23 (2006) ("Order 679"), *on reh'g*, Order No. 679-A, 72 Fed. Reg. 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2006), *clarified*, 119 FERC ¶ 61,062 (2007).

and therefore do[es] not generally permit 'single issue' rate filings." Nonetheless, as an *incentive* necessary to encourage the construction of new transmission, the Commission authorized utilities to make single-issue rate filings *in certain circumstances* to seek incentives without re-opening its transmission rates to review.[121] The Commission recognized that the right to make a single-issue filing was an incentive in and of itself. The Commission has also authorized single-issue filings to recover "smart grid" costs. The Commission explained that "the Commission will allow single issue rate treatment in response to a pressing need for the development of new and innovative smart grid capabilities that will be needed by the electric system, and in response to a statutory directive to support the modernization of the electric grid."[122] In the wake of the extraordinary circumstances of the September 11, 2001 terrorist attacks, the Commission stated that it would authorize a "separate rate recovery mechanism" in order to allow companies to timely recover the emergency expenditures necessary to safeguard the nation's infrastructure.[123] In sum, the Commission has not permitted single-issue rate filings except in very limited circumstances. JCP&L has provided no justification for allowing it to adjust selective components of its formula rate in future cases.

3. JCP&L must provide more than five days' notice of the Annual Projected Rate Meeting.

Section II.H of JCP&L's proposed protocols in Attachment H-4B of the Rate Filing provides that the Annual Projected Rate Meeting can be held five business days following the posting of the Projected Transmission Revenue Requirement. Five days'

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[121] *Id.* PP 29, 79.

[122] *Smart Grid Policy*, 128 FERC ¶ 61,060, P 136 (2009).

[123] *Extraordinary Expenditures Necessary to Safeguard Nat'l Energy Supplies*, 96 FERC ¶ 61,299, at 62,129 (2001).

notice, however, is insufficient to permit customers to make arrangements to attend the meeting and sufficiently review the posting to enable a meaningful discussion at the meeting. Moreover, JCP&L's proposal is inferior to the Commission's standards for protocols as embodied in the MISO formula rate protocols. Section II.E of the MISO protocols provides a minimum of seven days' notice prior to an annual meeting. JCP&L has offered no support for this change. The Commission should reject it.

III. REQUEST FOR MAXIMUM SUSPENSION AND REFUND EFFECTIVE DATE

As noted earlier, the Commission's *West Texas* policy[124] provides that if 10% of the proposed increase is excessive, then the Commission will suspend the rate for a full five months. That policy dictates that the Commission suspend JCP&L's proposed formula rate for five months. In this proceeding, JCP&L has proposed a rate increase of $8,120.10/MW-year (from $15,112.00/MW-year to $23,232.10/MW-year). Under the Commission's *West Texas* policy, if 10% of that proposed increase, or $812/MW-year, is excessive, then the JCP&L rate should be suspended for five months. The adjustments identified above more than meet this 10% threshold.

Although Indicated Intervenors lack sufficient data to fully quantify the rate impacts on JCP&L's proposed formula rate that result from correcting all of the above described deficiencies, Indicated Intervenors have attempted to quantify the impacts based on available information, including a live version of the formula rate in an Excel spreadsheet populated by JCP&L with projected 2017 data.[125] As explained in section II.A.4 above, we have attempted to quantify the impact of reducing JCP&L's Base ROE

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[124] *W. Tex. Utils. Co.*, 18 FERC ¶ 61,189 (1982).

[125] *See* Exs. 5-A, 5-B, 5-C, and 5-D.

and estimated that the ROE reduction alone reduces the transmission rate over $955/MW-year, or more than 10% of the rate increase sought by JCP&L.[126] In addition, at section II.C above, Indicated Intervenors have shown that JCP&L should not be permitted to collect its proposed $14.2 million vegetation management regulatory asset over the proposed seven years, further reducing the revenue requirement by over $2 million per year. This reduction in revenue requirement equates to a rate reduction of over $340/MW-year.[127] At section II.D above, Indicated Intervenors showed that JCP&L should not be permitted to shift $1.1 million in out-of-period regulatory expenses to 2017 which reduces the 2017 rate by over $184/MW-year.[128] And at section II.E above, Indicated Intervenors showed that JCP&L's use of an incorrect allocator to functionalize General and Intangible Plant costs reduces the JCP&L revenue requirement by about $5 million per year which reduces the 2017 rate by over $795/MW-year. The combination of each of these adjustments is over $2,274/MW-year, nearly triple the amount needed to show that JCP&L's proposed increase is 10% excessive. Accordingly, the Commission should suspend the JCP&L formula rate for the maximum five-month period.

As discussed above, JCP&L's formula rate contains serious flaws that render it unjust and unreasonable. Accordingly, in addition to a maximum five-month suspension, the Commission should only accept the filing subject to refund.

IV. REQUEST FOR HEARING AND SETTLEMENT JUDGE PROCEEDINGS

Indicated Intervenors have only had limited time to review the JCP&L formula rate, and that review is not complete. In order to ensure that the formula rate will operate

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[126] Ex. 5-A at 1, line 13.

[127] Ex. 5-B at 1, line 13.

[128] Ex. 5-C at 1, line 13.

in a just and reasonable manner, Indicated Intervenors require an opportunity to seek discovery against JCP&L, and to assess the information that is produced in response to those requests. Accordingly, the Commission should set these proceedings for hearing. Consistent with past practice in numerous prior formula transmission rate proceedings, the Commission should hold that hearing in abeyance and establish settlement proceedings before an Administrative Law Judge.

V. CONCLUSION

Wherefore, for the reasons stated above, the Commission should suspend JCP&L's proposed formula rate for the maximum five-month period, establish a refund effective date, and set the entire rate proposal for hearing to be held in abeyance to permit settlement discussions under the auspices of a Commission Administrative Law Judge.

Respectfully submitted,

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November 18, 2016

EXHIBIT 1

ER17-217-000
Exhibit 1
Page 1 of 3

Black Hills Corp (BKH)

BKH on New York Consolidated	Change (% chg)	Prev Close	Day's High	Volume	52-wk High
57.94USD	$-0.74 (-1.26%)	$58.68	$59.38	120,541	$64.58
16 Nov 2016		Open $58.68	Day's Low $57.65	Avg. Vol 377,623	52-wk Low $40.00

CONSENSUS RECOMMENDATIONS

Consensus Recommendation	Next Earnings (approx.)	Company Fiscal Year End Month	Last Updated
Outperform	0.96	December	16 Nov 2016

ANALYST RECOMMENDATIONS AND REVISIONS

1-5 Linear Scale	Current	1 Month Ago	2 Month Ago	3 Month Ago
(1) BUY	2	2	2	2
(2) OUTPERFORM	3	3	3	3
(3) HOLD	1	1	1	1
(4) UNDERPERFORM	0	0	0	0
(5) SELL	0	0	0	0
No Opinion	0	0	0	0
Mean Rating	1.83	1.83	1.83	1.83

CONSENSUS ESTIMATES ANALYSIS

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	# of Estimates	Mean	High	Low	1 Year Ago
SALES (in millions)					
Quarter Ending Dec-16	1	455.00	455.00	455.00	--
Quarter Ending Mar-17	1	464.21	464.21	464.21	--
Year Ending Dec-16	4	1,717.62	2,173.40	1,440.10	1,557.76
Year Ending Dec-17	5	1,913.42	2,326.30	1,523.00	1,618.14
Earnings (per share)					
Quarter Ending Dec-16	3	0.96	0.97	0.95	--

Quarter Ending Mar-17	2	0.97	1.46	0.48	--
Year Ending Dec-16	5	3.00	3.07	2.85	3.26
Year Ending Dec-17	6	3.55	3.61	3.45	3.32
LT Growth Rate (%)	1	6.70	6.70	6.70	3.48

HISTORICAL SURPRISES

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

Estimates vs Actual	Estimate	Actual	Difference	Surprise %
SALES (in millions)				
Quarter Ending Sep-16	414.77	333.80	80.97	19.52
Quarter Ending Jun-16	468.21	325.40	142.81	30.50
Quarter Ending Mar-16	488.73	449.96	38.77	7.93
Quarter Ending Dec-15	482.49	318.30	164.19	34.03
Quarter Ending Sep-15	340.68	272.10	68.58	20.13
Earnings (per share)				
Quarter Ending Sep-16	0.43	0.48	0.05	12.94
Quarter Ending Jun-16	0.53	0.39	0.14	26.87
Quarter Ending Mar-16	0.99	1.23	0.24	24.56
Quarter Ending Dec-15	0.67	0.71	0.04	6.77
Quarter Ending Sep-15	0.58	0.64	0.06	11.01

EARNINGS VS. ESTIMATES

Last Five Estimates

Q3 16 **0.48**
Q2 16 **0.39**
Q1 16 **1.23**
Q4 15 **0.71**
Q3 15 **0.64**

Future Estimates

Q4 16 **0.95**
Q1 17 **0.48**

» More Financials

BLACK HILLS CORP NEWS

BRIEF-Black Hills fy2017 earnings per share view $3.55 -- thomson reuters i/b/e/s

BRIEF-Black Hills Corp reports Q3 2016 results and updates earnings guidance

BRIEF-Black Hills - Issued $400 mln of 3.150% notes due 2027 and $300 mln of 4.200% notes due 2046

BRIEF-Black Hills announces pricing of $700 mln senior notes offering

BRIEF-Black Hills Corp upsizes revolving credit facility to $750 mln

» More BKH News

CONSENSUS ESTIMATES TREND

Sales and Profit Figures in US Dollar (USD)
Earnings and Dividend Figures in US Dollar (USD)

	Current	1 Week Ago	1 Month Ago	2 Month Ago	1 Year Ago
SALES (in millions)					
Quarter Ending Dec-16	455.00	746.42	746.42	746.42	--
Quarter Ending Mar-17	464.21	464.21	464.21	464.21	--
Year Ending Dec-16	1,717.62	1,777.37	1,784.67	1,784.67	1,557.76
Year Ending Dec-17	1,913.42	1,916.22	1,925.58	1,924.38	1,618.14
Earnings (per share)					
Quarter Ending Dec-16	0.96	1.02	1.10	1.10	--
Quarter Ending Mar-17	0.97	0.97	0.96	0.96	--
Year Ending Dec-16	3.00	3.01	3.01	3.01	3.26
Year Ending Dec-17	3.55	3.55	3.55	3.55	3.32

ESTIMATES REVISIONS SUMMARY

	Last Week		Last 4 Weeks	
Number Of Revisions:	**Up**	**Down**	**Up**	**Down**
Revenue				
Quarter Ending Dec-16	0	0	0	0
Quarter Ending Mar-17	0	0	0	0
Year Ending Dec-16	0	1	1	2
Year Ending Dec-17	0	1	1	3
Earnings				
Quarter Ending Dec-16	0	0	0	1

Quarter Ending Mar-17	0	0	1	0
Year Ending Dec-16	1	0	3	1
Year Ending Dec-17	0	1	3	1

EXHIBIT 2

ER17-217-000
Exhibit 2
Page 1 of 2

Black Hills Corporation (BKH)

☆ Add to watchlist

NYSE - NYSE Real Time Price. Currency in USD

Quote Lookup

58.14 -0.54 (-0.92%)

As of 3:13 PM EST. Market open.

People also watch:
VVC WGL IDA ATO MGEE

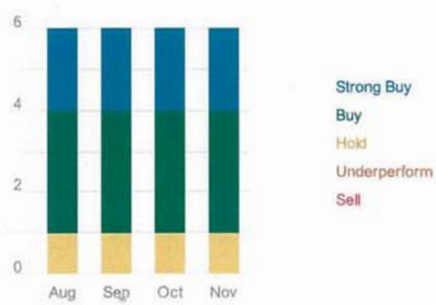
Summary Conversations Statistics Profile Financials Options Holders Historical Data Analysts

Currency in USD.

Earnings Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	2	2	5	6
Avg. Estimate	0.96	0.97	2.99	3.55
Low Estimate	0.95	0.48	2.85	3.45
High Estimate	0.97	1.46	3.07	3.61
Year Ago EPS	0.71	1.23	2.98	2.99

Revenue Estimate	Current Qtr.	Next Qtr.	Current Year	Next Year
No. of Analysts	1	1	4	5
Avg. Estimate	746.42M	464.21M	1.72B	1.92B
Low Estimate	746.42M	464.21M	1.44B	1.52B
High Estimate	746.42M	464.21M	2.17B	2.33B
Year Ago Sales	318.3M	449.96M	1.3B	1.72B
Sales Growth (year/est)	134.50%	3.20%	31.90%	11.30%

Recommendation Trends >



Earnings History	12/30/2015	3/30/2016	6/29/2016	9/29/2016
EPS Est.	0.67	0.99	0.53	0.43
EPS Actual	0.71	1.23	0.39	0.48
Difference	0.04	0.24	-0.14	0.05
Surprise %	6.00%	24.20%	-26.40%	11.60%

Recommendation Rating >

1.8

1 Strong Buy · 2 Buy · 3 Hold · 4 Under-perform · 5 Sell

Analyst Price Targets (5) >

Average 67.60

Current 58.14 · Low 65.00 · High 70.00

EPS Trend	Current Qtr.	Next Qtr.	Current Year	Next Year
Current Estimate	0.96	0.97	2.99	3.55

7 Days Ago	1.02	0.97	3	3.54
30 Days Ago	1.1	0.96	3.01	3.55
60 Days Ago	1.1	0.96	3.01	3.55
90 Days Ago	1.01	1.37	3.01	3.55

Down Last 30 Days	1	N/A	1	1
Down Last 90 Days	N/A	N/A	N/A	N/A

Growth Estimates	BKH	Industry	Sector	S&P 500
Current Qtr.	35.20%	22.29		
Next Qtr.	-21.10%	18.39		
Current Year	0.30%	13.98		
Next Year	18.70%	0.02		
Next 5 Years (per annum)	6.70%	0.07		
Past 5 Years (per annum)	11.95%	N/A		

Upgrades & Downgrades >

↑ Upgrade	BMO Capital Markets: Market Perform to Outperform	1/29/2016
↑ Upgrade	Williams Capital Group: Sell to Buy	1/19/2016
↓ Downgrade	RBC Capital Mkts: Outperform to Sector Perform	3/18/2013

More Upgrades & Downgrades

EXHIBIT 3

KeyBanc
Capital Markets

August 10, 2016

Energy: Electric Utilities

Earnings Recap

Otter Tail Corporation

OTTR: Utility and Manufacturing Show Strong Results

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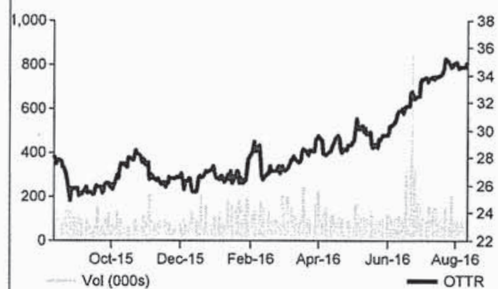
NASDAQ: OTTR	
Rating:	**Sector Weight**
Price Target:	**NA**
Price:	**$34.72**



Sources: Company reports, FactSet, KeyBanc Capital Markets Inc.

OTTR had a strong quarter as the Utility and Manufacturing segments showed positive YOY results; however, going forward, we remain cautious on the Manufacturing (softness in certain end markets) and Plastics (increasing COGS) segments as any economic slowdown could pressure earnings. We remain **Sector Weight** on shares of OTTR.

Key Investment Points

2Q16 Earnings Results: OTTR reported EPS of $0.41 vs. $0.36 in 2Q15 (KBCM of $0.38) as the Electric Segment improved YOY (+$0.03) driven by interim rates and weather; Manufacturing showed a YOY increase (+$0.03) largely from the benefit of incremental revenues associated with BTD Georgia; Plastics fell (-$0.02) on lower pricing; and Corporate improved (+$0.02) driven by COLI proceeds. We note $0.01 of rounding.

2016 EPS Guidance: The Company reaffirmed its 2016 EPS guidance range of $1.50-$1.65, however, made slight changes on a segment basis. The two primary changes from its previous guidance (Revised on May 2, 2016) are at the Electric Segment and at the Manufacturing Segment. At the Electric Segment the range has been lowered to $1.27-$1.30 from $1.29-$1.32, while at the Manufacturing Segment the range has been increased to $0.14-$0.18 from $0.12-$0.16. We reaffirm our 2016 EPS estimate of $1.60.

Integrated Resource Plan Filed: On June 1, 2016, OTTR filed its IRP with the MPUC, identifying the most cost effective combination of resources to meet customer needs. The plan, as proposed, has identified the following resource needs: 1) 100 MW of wind in 2018; 2) 100 MW of wind in 2020; 3) 30 MW of solar in 2020; 4) a 248 MW NG simple cycle plant in 2021; and 5) Up to 100 MW of wind, post 2022.

Rate Base Growth: In light of replacement capital, resource needs, as well as transmission investment, OTTR has a rate base CAGR of 8% from 2014 through 2020. Given the IRP highlights resource needs post 2020, we believe OTTR is well positioned to have the ability to grow rate base 8% per annum beyond 2020.

Pending Minnesota Rate Case: The Company's ask included: a $19.3 million rate increase, based on a 10.4% ROE and 52.5% equity layer. In mid-April OTTR implemented interim rates at $16.8 million as it seeks to recover rate-base additions, reagent costs, and expiration of Integrated Transmission and Regional Transmission Organization expenses. The GRC is expected to conclude by 1Q17, with interim rates subject to refund.

Unregulated Businesses: The vertical integration at BTD Manufacturing showed a benefit this quarter as the platform expansion enhanced margins; alternatively, the Plastics Segment experienced gross margin degradation as COGS increased. Under current economic conditions, we believe the unregulated segment bears watching.

Company Data

52-week range	$25 - $35
Market Cap. (M)	$1,307.2
Shares Out. (M)	37.65
Enterprise Value (M)	$1,890.2
Avg. Daily Volume (30D)	103,684.0
Annual Dividend	$1.25
Dividend Yield	3.6%
SI as % of Float	3.3%
SI % Chg. from Last Per.	0.1%
Book Value/Share	$15.63
Book Value/Share	$15.63

Sources: Company reports, FactSet, KeyBanc Capital Markets Inc.

Estimates

FY ends 12/31	F2015A	1Q16A	2Q16A	3Q16E	4Q16E	F2016E	F2017E
EPS (Net)	**$1.56**	**$0.38**	**$0.41**	**$0.42**	**--**	**$1.60**	**$1.60**
Cons. EPS	*--*	*$0.38*	*$0.41*	*$0.40*	*$0.42*	*$1.60*	*$1.60*
Previous	--	--	$0.38	--	--	--	--
Valuation							
P/E	22.3x	--	--	--	--	21.7x	21.7x

Sources: Company reports, FactSet, KeyBanc Capital Markets Inc.

Quarters may not sum to annual due to changes in shares outstanding and timing of discontinued operations.

For analyst certification and important disclosures, please refer to the Disclosure Appendix.

Valuation

We view OTTR as fairly valued at current trading levels as it currently trades at a P/E multiple of 21.7x our 2017 EPS estimate of $1.60, which compares to its peers current average of 18.4x. We remain **Sector Weight** on shares of OTTR.

Investment Risks

Macroeconomic Downturn. A prolonged macroeconomic downturn in Minnesota and the Dakotas could negatively impact OTTR's electric utility operations. A broader U.S. economic slowdown could negatively impact the outlooks for OTTR's Nonutility segments, Manufacturing, and Plastics.

Regulatory Environment. If the regulatory environment for OTTR's utilities becomes less constructive, this could negatively affect the earnings outlook and investor sentiment.

Rising Interest Rates. Rising interest rates would likely put pressure on utility valuation multiples and would erode the relative value of OTTR's dividend.

Weather. OTTR's electric utility operations are exposed to swings in demand related to fluctuations in weather conditions. Weather can also impact utilization and demand at its Plastics segment.

2Q16 Details

Guidance: The Company reaffirmed 2016 EPS guidance of $1.50-$1.65 as highlighted below:

		Original Guidance		May 2, 2016 Guidance		August 8, 2016 Guidance	
	2015 EPS by Segment	2016 EPS Low	2016 EPS High	2016 EPS Low	2016 EPS High	2016 EPS Low	2016 EPS High
Electric	$1.29	$1.29	$1.32	$1.29	$1.32	$1.27	$1.30
Manufacturing	$0.11	$0.11	$0.15	$0.12	$0.16	$0.14	$0.18
Plastics	$0.32	$0.26	$0.30	$0.24	$0.28	$0.24	$0.28
Corporate	($0.16)	($0.16)	($0.12)	($0.15)	($0.11)	($0.15)	($0.11)
Total-Continuing Operations	$1.56	$1.50	$1.65	$1.50	$1.65	$1.50	$1.65
Expected ROE		9.30%	10.20%	9.30%	10.20%	9.30%	10.20%

Source: Company Reports

- OTTR forecasts an 8% rate base CAGR for the 2014-2020 time frame.
- OTTR results were ahead of our estimate as various other items drove the delta.
- At the Electric Segment, EPS rose to $0.24 from $0.21 in 2Q15 primarily on the implementation of interim rates in Minnesota and more favorable weather.
  - CDD rose 60% vs. 2Q15 and 126% relative to normal.
  - HDD rose 5% vs. 2Q15 and 88% relative to normal.
- In the Manufacturing Segment, EPS rose to $0.08 vs. $0.05 in 2Q15 as the segment saw incremental revenues from the BTD-Georgia plant acquired in September 2015 and higher wind tower sales revenues at BTD. These were partly offset by lower agricultural and recreational equipment sales and cost of goods sold.
- Plastics fell to $0.09 vs. $0.11 per share as volumes of PVC rose while unit pricing fell.
- Corporate losses improved to a very slight loss vs. a $0.02 per share loss, driven by COLI proceeds.

Disclosure Appendix

Otter Tail Corporation - OTTR

We expect to receive or intend to seek compensation for investment banking services from Otter Tail Corporation within the next three months.

During the past 12 months, Otter Tail Corporation has been a client of the firm or its affiliates for non-securities related services.

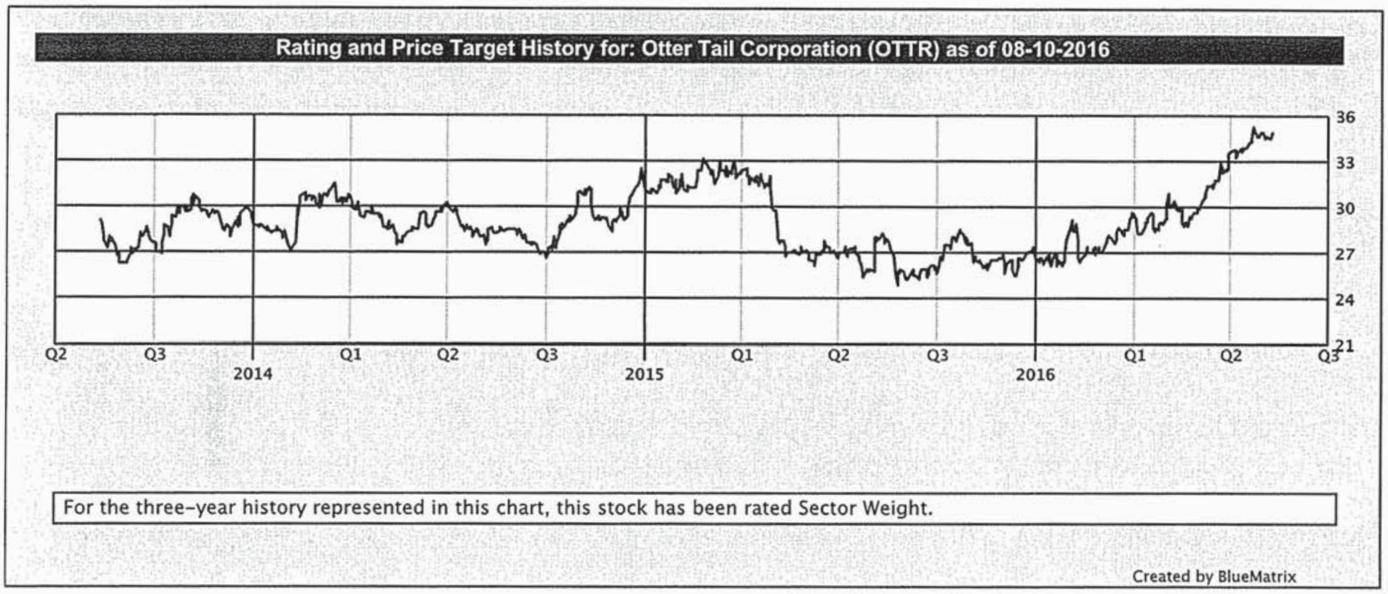
As of the date of this report, we make a market in Otter Tail Corporation.

For the three-year history represented in this chart, this stock has been rated Sector Weight.

Reg A/C Certification

The research analyst(s) responsible for the preparation of this research report certifies that:(1) all the views expressed in this research report accurately reflect the research analyst's personal views about any and all of the subject securities or issuers; and (2) no part of the research analyst's compensation was, is, or will be directly or indirectly related to the specific recommendations or views expressed by the research analyst(s) in this research report.

Three-Year Rating and Price Target History



Rating Disclosures

Distribution of Ratings/IB Services Firmwide and by Sector

KeyBanc Capital Markets			IB Serv/Past 12 Mos.		Energy			IB Serv/Past 12 Mos.	
Rating	Count	Percent	Count	Percent	Rating	Count	Percent	Count	Percent
Overweight [OW]	319	41.75	65	20.38	Overweight [OW]	37	42.05	20	54.05
Sector Weight [SW]	436	57.07	60	13.76	Sector Weight [SW]	51	57.95	19	37.25
Underweight [UW]	9	1.18	0	0.00	Underweight [UW]	0	0.00	0	0.00

Disclosure Appendix (cont'd)

Rating System

Overweight - We expect the stock to outperform the analyst's coverage sector over the coming 6-12 months.

Sector Weight - We expect the stock to perform in line with the analyst's coverage sector over the coming 6-12 months.

Underweight - We expect the stock to underperform the analyst's coverage sector over the coming 6-12 months.

Note: KeyBanc Capital Markets changed its rating system after market close on February 27, 2015. The previous ratings were Buy, Hold and Underweight. Additionally, Pacific Crest Securities changed its rating system to match KeyBanc Capital Markets' rating system after market close on April 10, 2015, in conjunction with the merger of the broker dealers. The previous ratings were Outperform, Sector Perform and Underperform.

Other Disclosures

KeyBanc Capital Markets is a trade name under which corporate and investment banking products and services of KeyCorp and its subsidiaries, KeyBanc Capital Markets Inc., Member NYSE/FINRA/SIPC ("KBCMI"), and KeyBank National Association ("KeyBank N.A."), are marketed. Pacific Crest Securities is a division of KeyBanc Capital Markets Inc.

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EXHIBIT 4

OFFICIAL COPY **EXHIBIT NO. S-3**

FEDERAL ENERGY REGULATORY COMMISSION
OFFICE OF ADMINISTRATIVE LITIGATION

ENE (Environment Northeast), et al.
v.
Bangor Hydro-Electric Company, et al.

Attorney General of the
Commonwealth of Massachusetts, et al.
v.
Bangor Hydro-Electric Company, et al.

DOCKET NOS. EL13-33-002
EL14-86-000

SCHEDULES

OF

TRIAL STAFF WITNESS

SABINA U. JOE

March 23, 2015
WASHINGTON, D.C. 20426

IBES Growth Rates
EL13-33 Period

Schedule 1

LONG TERM GROWTH IBES ESTIMATES

THOMSON REUTERS
Thomson Reuters on Demand
trondemand@thomsonreuters.com

NAME	LTG MEAN ESTIMATE AS OF 03/31/2014	LTG MEAN ESTIMATE - ALTERNATIVE DATE	LTG MEAN ESTIMATE	NOTES
ALLETE	-	9/25/2012	6	EXCLUDED AS OF 03/24/13*
ALLIANT ENERGY CORP.	5.4			
AMEREN	2			
AMER.ELEC.PWR.	4.23			
AVISTA	-	8/11/2013	5	EXCLUDED AS OF 02/07/14*
BLACK HILLS	7			
CENTERPOINT EN.	3.77			
CLECO	8			
CMS ENERGY	6.24			
CONSOLIDATED EDISON	2.31			
DOMINION RESOURCES	6.77			
DTE ENERGY	5.21			
DUKE ENERGY	3.92			
EDISON INTL.	0.95			
EL PASO ELEC.	-	9/15/2011	3.7	EXCLUDED AS OF 03/14/12*
EMPIRE DST.ELEC.	3			
ENTERGY	-1.9			
EXELON	-4.8			
FIRSTENERGY	-1.38			
GREAT PLAINS EN.	5.25			
HAWAIIAN ELECTRIC INDS.	4.2			
IDACORP	4			
INTEGRYS ENERGY GROUP	-	12/15/2013	5.7	EXCLUDED AS OF 03/19/14 BY THE BROKER(S)
ITC HOLDINGS	12			
MGE ENERGY	-	3/2/2011	4	EXCLUDED AS OF 02/05/12*
NEXTERA ENERGY	6.47			
NORTHEAST UTILITIES	6.28			
NORTHWESTERN	7			
OGE ENERGY	-	12/19/2013	5	EXCLUDED AS OF 02/19/14 BY THE BROKER(S)
OTTER TAIL	-	5/13/2013	6	EXCLUDED AS OF 02/09/14*
PEPCO HOLDINGS	7.2			
PG&E	6.65			
PNM RESOURCES	9.4			
PINNACLE WEST CAP.	4.13			
PORTLAND GEN.ELEC.	6.6			
PPL	0.67			
PUB.SER.ENTER.GP.	1.9			
SCANA	4.6			
SEMPRA EN.	6.28			
SOUTHERN	3.55			
TECO ENERGY	-	8/2/2013	5	EXCLUDED AS OF 01/30/14* BUT RESUMED ON 05/15/2014
UIL HOLDINGS	5.23			
UNITIL	-	1/12/2011	1.9	EXCLUDED AS OF 01/23/2011 DUE TO ACCOUNTING DIFFERENCE
UNS ENERGY DEAD - DELIST.18/08/14	-	5/17/2012	8	EXCLUDED AS OF 11/14/12*
VECTREN	4			
WESTAR ENERGY	2.8			
WISCONSIN ENERGY	4.86			
XCEL ENERGY	4.62			

Source: Thomson Reuters

*AFTER 180 DAYS OF NOT BEING REVISED, THE ESTIMATE IS REMOVED

EXHIBIT 5-A

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

Jersey Central Power & Light

Line No.			Total		Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 43, col 5]						$ 146,233,264
	REVENUE CREDITS	(Note T)	Total		Allocator		
2	Account No. 451	(page 4, line 29)	-		TP	1.00000	-
3	Account No. 454	(page 4, line 30)	-		TP	1.00000	-
4	Account No. 456	(page 4, line 31)	1,074,828		TP	1.00000	1,074,828
5	Revenues from Grandfathered Interzonal Transactions		-		TP	1.00000	-
6	Revenues from service provided by the ISO at a discount		-		TP	1.00000	-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	12,504,161		TP	1.00000	12,504,161
8	TOTAL REVENUE CREDITS (sum lines 2-7)		13,578,989				13,578,989
9	True-up Adjustment with Interest	Attachment 13, Line 28					-
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)					$ 132,654,275

Line No.	DIVISOR					Total
11	1 Coincident Peak (CP) (MW)				(Note A)	5,954.8
12	Average 12 CPs (MW)				(Note CC)	4,034.6

Line No.			Total	As-filed	Decrease
13	**Adjusted Annual Rate ($/MW/Yr)@9.75% ROE**	(line 10 / line 11)	**22,276.92**	**$23,232.10**	**$955.18**

Line No.			Peak Rate Total	Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	32,879.56	32,879.56
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	2,739.96	2,739.96
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	632.30	632.30
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	126.46	90.33
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	7.90	3.75

ADJUSTED-ROE VERSION OF Attachment H-4A
page 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)	44,157,831	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,387,609,306	TP	1.00000	1,387,609,306
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	4,585,334,757	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	406,818,923	GP	0.23061	93,816,879
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	0.05961	-
6	TOTAL GROSS PLANT (sum lines 1-5)		6,423,920,817	GP=	23.061%	1,481,426,185
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	20,711,040	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	372,617,994	TP	1.00000	372,617,994
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	1,410,141,577	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	278,481,191	GP	0.23061	64,220,799
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	0.05961	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,081,951,802			436,838,793
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	23,446,791			
14	Transmission	(line 2- line 8)	1,014,991,312			1,014,991,312
15	Distribution	(line 3 - line 9)	3,175,193,180			
16	General & Intangible	(line 4 - line 10)	128,337,731			29,596,080
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		4,341,969,014	NP=	24.058%	1,044,587,392
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 3, Col. 1 (Notes C, F, Y)	-	NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 3, Col. 2 (Note C, F, Y)	(319,680,605)	DA	1.00000	(319,680,605)
21	Account No. 283 (enter negative)	Attachment 5, Line 3, Col. 3 (Notes C, F, Y)	(11,663,397)	DA	1.00000	(11,663,397)
22	Account No. 190	Attachment 5, Line 3, Col. 4 (Notes C, F, Y)	7,459,781	DA	1.00000	7,459,781
23	Account No. 255 (enter negative)	Attachment 5, Line 3, Col. 5 (Notes C, F, Y)	(1,982,947)	DA	1.00000	(1,982,947)
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 6, Col. 6 (Notes C & Y)	-	DA	1.00000	-
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 9, Col. 6 (Notes C & Y)	-	DA	1.00000	-
26	CWIP	216.b (Notes X & Z)	-	DA	1.00000	-
27	Unamortized Regulatory Asset	Attachment 16a, 16b, 16c, Line 15, Col. 7 (Note X)	25,800,648	DA	1.00000	25,800,648
28	Unamortized Abandoned Plant	Attachment 17, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
29	TOTAL ADJUSTMENTS (sum lines 19-28)		(300,066,519)			(300,066,519)
30	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)	-	TP	1.00000	-
31	WORKING CAPITAL (Note H)					
32	CWC	1/8*(Page 3, Line 15 minus Page 3, Lines 11 & 12)	10,876,876			3,374,339
33	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)	-	TE	0.94480	-
34	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)	1,649,218	GP	0.23061	380,328
35	TOTAL WORKING CAPITAL (sum lines 32 - 34)		12,526,094			3,754,667
36	RATE BASE (sum lines 18, 29, 30, & 35)		4,054,428,589			748,275,540

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b	25,133,908	TE	0.94480	23,746,587
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		-	DA	1.00000	-
3	Less Account 565	321.96.b	-	DA	1.00000	-
4	Less Account 566	321.97.b	(7,913,701)	DA	1.00000	(7,913,701)
5	A&G	323.197.b	62,349,851	W/S	0.05961	3,716,878
6	Less FERC Annual Fees		-	W/S	0.05961	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		-	W/S	0.05961	-
8	Plus Transmission Related Reg. Comm. Exp. (Note I)		-	TE	0.94480	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 9 (Note C)	(468,750)	DA	1.00000	(468,750)
10	Common	356.1	-	CE	0.05961	-
11	Account 407.3 Amortization of Regulatory Assets	Attachment 16a, 16b, 16c, Line 15, Col. 5	5,368,533	DA	1.00000	5,368,533
12	Account 566 Amortization of Regulatory Assets		-	DA	1.00000	-
13	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 12	(7,913,701)	DA	1.00000	(7,913,701)
14	Total Account 566 (sum lines 12 & 13, ties to 321.97.b)		(7,913,701)			(7,913,701)
15	TOTAL O&M (sum lines 1, 5,8, 9, 10, 11, 14 less 2, 3, 4, 6, 7)		92,383,542			32,363,249
	DEPRECIATION AND AMORTIZATION EXPENSE					
16	Transmission	336.7.b (Note U)	30,076,277	TP	1.00000	30,076,277
17	General & Intangible	336.1.f & 336.10.f (Note U)	16,201,290	GP	0.23061	3,736,194
18	Common	336.11.b (Note U)	-	CE	0.05961	-
19	Amortization of Abandoned Plant	Attachment 17, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
20	TOTAL DEPRECIATION (sum lines 16 -19)		46,277,567			33,812,471
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
21	Payroll	263.i (Attachment 7, line 1z)	10,835,432	W/S	0.05961	645,935
22	Highway and vehicle	263.i (Attachment 7, line 2z)	8,096	W/S	0.05961	483
23	PLANT RELATED					
24	Property	263.i (Attachment 7, line 3z)	6,023,392	GP	0.23061	1,389,060
25	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
26	Other	263.i (Attachment 7, line 5z)	3,618	GP	0.23061	834
27	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	0.23061	-
28	TOTAL OTHER TAXES (sum lines 21 - 27)		16,870,538			2,036,312
	INCOME TAXES	(Note K)				
29	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.85%			
30	CIT=(T/1-T) * (1-(WCLTD/R)) =		36.41%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
31	1 / (1 - T) = (from line 30)		1.6906			
32	Amortized Investment Tax Credit (266.8.f) (enter negative)		(131,199)			
33	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) [Notes D & Y]		1,640,804			
34	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) [Notes E & Y]		-			
35	Income Tax Calculation = line 30 * line 40		108,070,180	NA		19,945,171
36	ITC adjustment (line 31 * line 32)		(221,807)	NP	0.24058	(53,362)
37	Permanent Differences and AFUDC Equity Tax Adjustment (line 31 * line 33)		2,773,971	DA	1.00000	2,773,971
38	(Excess)/Deficient Deferred Income Tax Adjustment (line 31 * line 34)		-	DA	1.00000	-
39	Total Income Taxes	sum lines 35 through 38	110,622,344			22,665,780
40	RETURN [Rate Base (page 2, line 36) * Rate of Return (page 4, line 25, col. 6)]		296,838,110.91	NA		54,783,724
41	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE) (sum lines 15, 20, 28, 39, 40)		562,992,102			145,661,536
42	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)	571,727			571,727
43	GROSS REV. REQUIREMENT (line 41 + line 42)		563,563,830			146,233,264

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Jersey Central Power & Light

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (page 2, line 2, column 3)						1,387,609,306		
2	Less transmission plant excluded from ISO rates (Note M)						-		
3	Less transmission plant included in OATT Ancillary Services (Note N)						-		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,387,609,306		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (page 3, line 1, column 3)						25,133,908		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,387,321		
8	Included transmission expenses (line 6 less line 7)						23,746,587		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.94480		
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.94480		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	-	0.00	-				
13	Transmission	354.21.b	3,518,540	1.00	3,518,540				
14	Distribution	354.23.b	37,236,683	0.00	-		W&S Allocator		
15	Other	354.24,25,26.b	18,267,549	0.00	-		($ / Allocation)		
16	Total (sum lines 12-15)		59,022,772		3,518,540	=	0.05961	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)								
			$		% Electric		W&S Allocator		
17	Electric	200.3.c	-		(line 17 / line 20)		(line 16, col. 6)		CE
18	Gas	201.3.d	-		1.00000	*	0.05961	=	0.05961
19	Water	201.3.e	-						
20	Total (sum lines 17 - 19)		-						
	RETURN (R)						$		
21		Preferred Dividends (118.29c) (positive number)					-		
					Cost				
			$	%	(Note P)		Weighted		
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)		1,815,384,615	60%	0.0573		0.0346	=WCLTD	
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)		-	0%	0.0000		0.0000		
24	Common Stock Attachment 8, Line 14, Col. 6) (Note X)		1,189,489,334	40%	0.0975		0.0386		
25	Total (sum lines 22-24)		3,004,873,949				0.0732	=R	
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)					
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						-		
27	b. Bundled Sales for Resale included in Divisor on page 1						-		
28	Total of (a)-(b)						-		
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)			(300.17.b)			-		
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			(300.19.b)			-		
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)			(330.x.n)			1,074,828		

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Jersey Central Power & Light

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT.
B	Prepayments shall exclude prepayments of income taxes.
C	Transmission-related only
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Amounts to be included will be January 1, 2017 and thereafter.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 15, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 31).

Inputs Required:	FIT =	35.00%	
	SIT=	9.00%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test.
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = Attachment 10, Column (j) total. Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by it own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.

EXHIBIT 5-B

REMOVED OUT-OF-PERIOD VEGETATION MANAGEMENT REGULATORY ASSET VERSION

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

Jersey Central Power & Light

Line No.			Total		Allocator			Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 43, col 5]						$	151,921,201
	REVENUE CREDITS	(Note T)	Total		Allocator			
2	Account No. 451	(page 4, line 29)	-		TP	1.00000		-
3	Account No. 454	(page 4, line 30)	-		TP	1.00000		-
4	Account No. 456	(page 4, line 31)	1,074,828		TP	1.00000		1,074,828
5	Revenues from Grandfathered Interzonal Transactions		-		TP	1.00000		-
6	Revenues from service provided by the ISO at a discount		-		TP	1.00000		-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	12,504,161		TP	1.00000		12,504,161
8	TOTAL REVENUE CREDITS (sum lines 2-7)		13,578,989					13,578,989
9	True-up Adjustment with Interest	Attachment 13, Line 28						-
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)					$	138,342,213
10a	Less Vegetation Management Regulatory Asset	(Line 10 - 14,200,000/7)					$	136,313,641.16
	DIVISOR							Total
11	1 Coincident Peak (CP) (MW)					(Note A)		5,954.8
12	Average 12 CPs (MW)					(Note CC)		4,034.6
			Total	As-filed	Decrease			
13	Adjusted Annual Rate ($/MW/Yr)	(line 10a / line 11)	22,891.44	**$23,232.10**	**$340.66**			
			Peak Rate Total					Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	34,289.37					34,289.37
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	2,857.45					2,857.45
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	659.41					659.41
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	131.88					94.20
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	8.24					3.91

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)	44,157,831	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,387,609,306	TP	1.00000	1,387,609,306
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	4,585,334,757	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	406,818,923	GP	0.23061	93,816,879
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	0.05961	-
6	TOTAL GROSS PLANT (sum lines 1-5)		6,423,920,817	GP=	23.061%	1,481,426,185
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	20,711,040	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	372,617,994	TP	1.00000	372,617,994
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	1,410,141,577	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	278,481,191	GP	0.23061	64,220,799
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	0.05961	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,081,951,802			436,838,793
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	23,446,791			
14	Transmission	(line 2- line 8)	1,014,991,312			1,014,991,312
15	Distribution	(line 3 - line 9)	3,175,193,180			
16	General & Intangible	(line 4 - line 10)	128,337,731			29,596,080
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		4,341,969,014	NP=	24.058%	1,044,587,392
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 3, Col. 1 (Notes C, F, Y)	-	NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 3, Col. 2 (Note C, F, Y)	(319,680,605)	DA	1.00000	(319,680,605)
21	Account No. 283 (enter negative)	Attachment 5, Line 3, Col. 3 (Notes C, F, Y)	(11,663,397)	DA	1.00000	(11,663,397)
22	Account No. 190	Attachment 5, Line 3, Col. 4 (Notes C, F, Y)	7,459,781	DA	1.00000	7,459,781
23	Account No. 255 (enter negative)	Attachment 5, Line 3, Col. 5 (Notes C, F, Y)	(1,982,947)	DA	1.00000	(1,982,947)
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 6, Col. 6 (Notes C & Y)	-	DA	1.00000	-
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 9, Col. 6 (Notes C & Y)	-	DA	1.00000	-
26	CWIP	216.b (Notes X & Z)	-	DA	1.00000	-
27	Unamortized Regulatory Asset	Attachment 16a, 16b, 16c, Line 15, Col. 7 (Note X)	25,800,648	DA	1.00000	25,800,648
28	Unamortized Abandoned Plant	Attachment 17, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
29	TOTAL ADJUSTMENTS (sum lines 19-28)		(300,066,519)			(300,066,519)
30	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)	-	TP	1.00000	-
31	WORKING CAPITAL (Note H)					
32	CWC	1/8*(Page 3, Line 15 minus Page 3, Lines 11 & 12)	10,876,876			3,374,339
33	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)	-	TE	0.94480	-
34	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)	1,649,218	GP	0.23061	380,328
35	TOTAL WORKING CAPITAL (sum lines 32 - 34)		12,526,094			3,754,667
36	RATE BASE (sum lines 18, 29, 30, & 35)		4,054,428,589			748,275,540

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b	25,133,908	TE	0.94480	23,746,587
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		-	DA	1.00000	-
3	Less Account 565	321.96.b	-	DA	1.00000	-
4	Less Account 566	321.97.b	(7,913,701)	DA	1.00000	(7,913,701)
5	A&G	323.197.b	62,349,851	W/S	0.05961	3,716,878
6	Less FERC Annual Fees		-	W/S	0.05961	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		-	W/S	0.05961	-
8	Plus Transmission Related Reg. Comm. Exp. (Note I)		-	TE	0.94480	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 9 (Note C)	(468,750)	DA	1.00000	(468,750)
10	Common	356.1	-	CE	0.05961	-
11	Account 407.3 Amortization of Regulatory Assets	Attachment 16a, 16b, 16c, Line 15, Col. 5	5,368,533	DA	1.00000	5,368,533
12	Account 566 Amortization of Regulatory Assets		-	DA	1.00000	-
13	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 12	(7,913,701)	DA	1.00000	(7,913,701)
14	Total Account 566 (sum lines 12 & 13, ties to 321.97.b)		(7,913,701)			(7,913,701)
15	TOTAL O&M (sum lines 1, 5,8, 9, 10, 11, 14 less 2, 3, 4, 6, 7)		92,383,542			32,363,249
	DEPRECIATION AND AMORTIZATION EXPENSE					
16	Transmission	336.7.b (Note U)	30,076,277	TP	1.00000	30,076,277
17	General & Intangible	336.1.f & 336.10.f (Note U)	16,201,290	GP	0.23061	3,736,194
18	Common	336.11.b (Note U)	-	CE	0.05961	-
19	Amortization of Abandoned Plant	Attachment 17, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
20	TOTAL DEPRECIATION (sum lines 16 -19)		46,277,567			33,812,471
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
21	Payroll	263.i (Attachment 7, line 1z)	10,835,432	W/S	0.05961	645,935
22	Highway and vehicle	263.i (Attachment 7, line 2z)	8,096	W/S	0.05961	483
23	PLANT RELATED					
24	Property	263.i (Attachment 7, line 3z)	6,023,392	GP	0.23061	1,389,060
25	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
26	Other	263.i (Attachment 7, line 5z)	3,618	GP	0.23061	834
27	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	0.23061	-
28	TOTAL OTHER TAXES (sum lines 21 - 27)		16,870,538			2,036,312
	INCOME TAXES	(Note K)				
29	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.85%			
30	CIT=(T/1-T) * (1-(WCLTD/R)) =		38.47%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
31	1 / (1 - T) = (from line 30)		1.6906			
32	Amortized Investment Tax Credit (266.8.f) (enter negative)		(131,199)			
33	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) [Notes D & Y]		1,640,804			
34	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) [Notes E & Y]		-			
35	Income Tax Calculation = line 30 * line 40		121,925,332	NA		22,502,245
36	ITC adjustment (line 31 * line 32)		(221,807)	NP	0.24058	(53,362)
37	Permanent Differences and AFUDC Equity Tax Adjustment (line 31 * line 33)		2,773,971	DA	1.00000	2,773,971
38	(Excess)/Deficient Deferred Income Tax Adjustment (line 31 * line 34)		-	DA	1.00000	-
39	Total Income Taxes	sum lines 35 through 38	124,477,495			25,222,853
40	RETURN [Rate Base (page 2, line 36) * Rate of Return (page 4, line 25, col. 6)]		316,900,098.71	NA		58,486,316
41	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE) (sum lines 15, 20, 28, 39, 40)		596,909,241			151,921,201
42	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)	0			0
43	GROSS REV. REQUIREMENT (line 41 + line 42)		596,909,241			151,921,201

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Jersey Central Power & Light

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (page 2, line 2, column 3)						1,387,609,306		
2	Less transmission plant excluded from ISO rates (Note M)						-		
3	Less transmission plant included in OATT Ancillary Services (Note N)						-		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,387,609,306		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (page 3, line 1, column 3)						25,133,908		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,387,321		
8	Included transmission expenses (line 6 less line 7)						23,746,587		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.94480		
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.94480		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	-	0.00	-				
13	Transmission	354.21.b	3,518,540	1.00	3,518,540				
14	Distribution	354.23.b	37,236,683	0.00	-		W&S Allocator		
15	Other	354.24,25,26.b	18,267,549	0.00	-		($ / Allocation)		
16	Total (sum lines 12-15)		59,022,772		3,518,540	=	0.05961	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)								
			$		% Electric (line 17 / line 20)		W&S Allocator (line 16, col. 6)		CE
17	Electric	200.3.c	-						
18	Gas	201.3.d	-		1.00000	*	0.05961	=	0.05961
19	Water	201.3.e	-						
20	Total (sum lines 17 - 19)		-						
	RETURN (R)						$		
21		Preferred Dividends (118.29c) (positive number)					-		
			$	%	Cost (Note P)		Weighted		
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)		1,815,384,615	60%	0.0573		0.0346	=WCLTD	
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)		-	0%	0.0000		0.0000		
24	Common Stock Attachment 8, Line 14, Col. 6) (Note X)		1,189,489,334	40%	0.1100		0.0435		
25	Total (sum lines 22-24)		3,004,873,949				0.0782	=R	
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)					
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						-		
27	b. Bundled Sales for Resale included in Divisor on page 1						-		
28	Total of (a)-(b)						-		
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)			(300.17.b)			-		
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			(300.19.b)			-		
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)			(330.x.n)			1,074,828		

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Jersey Central Power & Light

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT.
B	Prepayments shall exclude prepayments of income taxes.
C	Transmission-related only
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Amounts to be included will be January 1, 2017 and thereafter.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 15, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 31).

Inputs Required:	FIT =	35.00%	
	SIT=	9.00%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test.
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = Attachment 10, Column (j) total. Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by it own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.

EXHIBIT 5-C

REMOVED OUT-OF-PERIOD REGULATORY EXPENSE REGULATORY ASSET VERSION

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

Jersey Central Power & Light

Line No.			Total		Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 43, col 5]						$ 151,921,201
	REVENUE CREDITS	(Note T)	Total		Allocator		
2	Account No. 451	(page 4, line 29)	-	TP		1.00000	-
3	Account No. 454	(page 4, line 30)	-	TP		1.00000	-
4	Account No. 456	(page 4, line 31)	1,074,828	TP		1.00000	1,074,828
5	Revenues from Grandfathered Interzonal Transactions		-	TP		1.00000	-
6	Revenues from service provided by the ISO at a discount		-	TP		1.00000	-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	12,504,161	TP		1.00000	12,504,161
8	TOTAL REVENUE CREDITS (sum lines 2-7)		13,578,989				13,578,989
9	True-up Adjustment with Interest	Attachment 13, Line 28					-
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)					$ 138,342,213
10a	Less Regulatory Expense Regulatory Asset	(Line 10 - 1,100,000)					$ 137,242,212.58

	DIVISOR			Total
11	1 Coincident Peak (CP) (MW)		(Note A)	5,954.8
12	Average 12 CPs (MW)		(Note CC)	4,034.6

			Total	As-filed	Decrease
13	Adjusted Annual Rate ($/MW/Yr)	(line 10a / line 11)	23,047.38	**$23,232.10**	**$184.72**

			Peak Rate Total	Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	34,289.37	34,289.37
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	2,857.45	2,857.45
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	659.41	659.41
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	131.88	94.20
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	8.24	3.91

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For the 12 months ended 12/31/2017

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)	44,157,831	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,387,609,306	TP	1.00000	1,387,609,306
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	4,585,334,757	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	406,818,923	GP	0.23061	93,816,879
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	0.05961	-
6	TOTAL GROSS PLANT (sum lines 1-5)		6,423,920,817	GP=	23.061%	1,481,426,185
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	20,711,040	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	372,617,994	TP	1.00000	372,617,994
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	1,410,141,577	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	278,481,191	GP	0.23061	64,220,799
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	0.05961	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,081,951,802			436,838,793
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	23,446,791			
14	Transmission	(line 2- line 8)	1,014,991,312			1,014,991,312
15	Distribution	(line 3 - line 9)	3,175,193,180			
16	General & Intangible	(line 4 - line 10)	128,337,731			29,596,080
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		4,341,969,014	NP=	24.058%	1,044,587,392
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 3, Col. 1 (Notes C, F, Y)	-	NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 3, Col. 2 (Note C, F, Y)	(319,680,605)	DA	1.00000	(319,680,605)
21	Account No. 283 (enter negative)	Attachment 5, Line 3, Col. 3 (Notes C, F, Y)	(11,663,397)	DA	1.00000	(11,663,397)
22	Account No. 190	Attachment 5, Line 3, Col. 4 (Notes C, F, Y)	7,459,781	DA	1.00000	7,459,781
23	Account No. 255 (enter negative)	Attachment 5, Line 3, Col. 5 (Notes C, F, Y)	(1,982,947)	DA	1.00000	(1,982,947)
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 6, Col. 6 (Notes C & Y)	-	DA	1.00000	-
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 9, Col. 6 (Notes C & Y)	-	DA	1.00000	-
26	CWIP	216.b (Notes X & Z)	-	DA	1.00000	-
27	Unamortized Regulatory Asset	Attachment 16a, 16b, 16c, Line 15, Col. 7 (Note X)	25,800,648	DA	1.00000	25,800,648
28	Unamortized Abandoned Plant	Attachment 17, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
29	TOTAL ADJUSTMENTS (sum lines 19-28)		(300,066,519)			(300,066,519)
30	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)	-	TP	1.00000	-
31	WORKING CAPITAL (Note H)					
32	CWC	1/8*(Page 3, Line 15 minus Page 3, Lines 11 & 12)	10,876,876			3,374,339
33	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)	-	TE	0.94480	-
34	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)	1,649,218	GP	0.23061	380,328
35	TOTAL WORKING CAPITAL (sum lines 32 - 34)		12,526,094			3,754,667
36	RATE BASE (sum lines 18, 29, 30, & 35)		4,054,428,589			748,275,540

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Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b	25,133,908	TE	0.94480	23,746,587
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		-	DA	1.00000	-
3	Less Account 565	321.96.b	-	DA	1.00000	-
4	Less Account 566	321.97.b	(7,913,701)	DA	1.00000	(7,913,701)
5	A&G	323.197.b	62,349,851	W/S	0.05961	3,716,878
6	Less FERC Annual Fees		-	W/S	0.05961	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		-	W/S	0.05961	-
8	Plus Transmission Related Reg. Comm. Exp. (Note I)		-	TE	0.94480	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 9 (Note C)	(468,750)	DA	1.00000	(468,750)
10	Common	356.1	-	CE	0.05961	-
11	Account 407.3 Amortization of Regulatory Assets	Attachment 16a, 16b, 16c, Line 15, Col. 5	5,368,533	DA	1.00000	5,368,533
12	Account 566 Amortization of Regulatory Assets		-	DA	1.00000	-
13	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 12	(7,913,701)	DA	1.00000	(7,913,701)
14	Total Account 566 (sum lines 12 & 13, ties to 321.97.b)		(7,913,701)			(7,913,701)
15	TOTAL O&M (sum lines 1, 5,8, 9, 10, 11, 14 less 2, 3, 4, 6, 7)		92,383,542			32,363,249
	DEPRECIATION AND AMORTIZATION EXPENSE					
16	Transmission	336.7.b (Note U)	30,076,277	TP	1.00000	30,076,277
17	General & Intangible	336.1.f & 336.10.f (Note U)	16,201,290	GP	0.23061	3,736,194
18	Common	336.11.b (Note U)	-	CE	0.05961	-
19	Amortization of Abandoned Plant	Attachment 17, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
20	TOTAL DEPRECIATION (sum lines 16 -19)		46,277,567			33,812,471
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
21	Payroll	263.i (Attachment 7, line 1z)	10,835,432	W/S	0.05961	645,935
22	Highway and vehicle	263.i (Attachment 7, line 2z)	8,096	W/S	0.05961	483
23	PLANT RELATED					
24	Property	263.i (Attachment 7, line 3z)	6,023,392	GP	0.23061	1,389,060
25	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
26	Other	263.i (Attachment 7, line 5z)	3,618	GP	0.23061	834
27	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	0.23061	-
28	TOTAL OTHER TAXES (sum lines 21 - 27)		16,870,538			2,036,312
	INCOME TAXES	(Note K)				
29	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.85%			
30	CIT=(T/1-T) * (1-(WCLTD/R)) =		38.47%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
31	1 / (1 - T) = (from line 30)		1.6906			
32	Amortized Investment Tax Credit (266.8.f) (enter negative)		(131,199)			
33	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) [Notes D & Y]		1,640,804			
34	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) [Notes E & Y]		-			
35	Income Tax Calculation = line 30 * line 40		121,925,332	NA		22,502,245
36	ITC adjustment (line 31 * line 32)		(221,807)	NP	0.24058	(53,362)
37	Permanent Differences and AFUDC Equity Tax Adjustment (line 31 * line 33)		2,773,971	DA	1.00000	2,773,971
38	(Excess)/Deficient Deferred Income Tax Adjustment (line 31 * line 34)		-	DA	1.00000	-
39	Total Income Taxes	sum lines 35 through 38	124,477,495			25,222,853
40	RETURN [Rate Base (page 2, line 36) * Rate of Return (page 4, line 25, col. 6)]		316,900,098.71	NA		58,486,316
41	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE) (sum lines 15, 20, 28, 39, 40)		596,909,241			151,921,201
42	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)	0			0
43	GROSS REV. REQUIREMENT (line 41 + line 42)		596,909,241			151,921,201

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Jersey Central Power & Light

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (page 2, line 2, column 3)						1,387,609,306		
2	Less transmission plant excluded from ISO rates (Note M)						-		
3	Less transmission plant included in OATT Ancillary Services (Note N)						-		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,387,609,306		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (page 3, line 1, column 3)						25,133,908		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,387,321		
8	Included transmission expenses (line 6 less line 7)						23,746,587		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.94480		
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.94480		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	-	0.00	-				
13	Transmission	354.21.b	3,518,540	1.00	3,518,540				
14	Distribution	354.23.b	37,236,683	0.00	-		W&S Allocator		
15	Other	354.24,25,26.b	18,267,549	0.00	-		($ / Allocation)		
16	Total (sum lines 12-15)		59,022,772		3,518,540	=	0.05961	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)								
			$		% Electric (line 17 / line 20)		W&S Allocator (line 16, col. 6)		CE
17	Electric	200.3.c	-						
18	Gas	201.3.d	-		1.00000	*	0.05961	=	0.05961
19	Water	201.3.e	-						
20	Total (sum lines 17 - 19)		-						
	RETURN (R)						$		
21		Preferred Dividends (118.29c) (positive number)					-		
			$	%	Cost (Note P)		Weighted		
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)		1,815,384,615	60%	0.0573		0.0346	=WCLTD	
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)		-	0%	0.0000		0.0000		
24	Common Stock Attachment 8, Line 14, Col. 6) (Note X)		1,189,489,334	40%	0.1100		0.0435		
25	Total (sum lines 22-24)		3,004,873,949				0.0782	=R	
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)					
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						-		
27	b. Bundled Sales for Resale included in Divisor on page 1						-		
28	Total of (a)-(b)						-		
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)			(300.17.b)			-		
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			(300.19.b)			-		
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)			(330.x.n)			1,074,828		

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Jersey Central Power & Light

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT.
B	Prepayments shall exclude prepayments of income taxes.
C	Transmission-related only
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Amounts to be included will be January 1, 2017 and thereafter.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 15, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 31).

Inputs Required:	FIT =	35.00%	
	SIT=	9.00%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test.
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = Attachment 10, Column (j) total. Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by it own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.

EXHIBIT 5-D

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

Jersey Central Power & Light

Line No.			Total			Allocator		Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 43, col 5]							$ 146,776,705
	REVENUE CREDITS	(Note T)	Total			Allocator		
2	Account No. 451	(page 4, line 29)	-			TP	1.00000	-
3	Account No. 454	(page 4, line 30)	-			TP	1.00000	-
4	Account No. 456	(page 4, line 31)	1,074,828			TP	1.00000	1,074,828
5	Revenues from Grandfathered Interzonal Transactions		-			TP	1.00000	-
6	Revenues from service provided by the ISO at a discount		-			TP	1.00000	-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	12,094,914			TP	1.00000	12,094,914
8	TOTAL REVENUE CREDITS (sum lines 2-7)		13,169,742					13,169,742
9	True-up Adjustment with Interest	Attachment 13, Line 28						-
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)						$ 133,606,963
	DIVISOR							Total
11	1 Coincident Peak (CP) (MW)					(Note A)		5,954.8
12	Average 12 CPs (MW)					(Note CC)		4,034.6
			Total	As-filed	Decrease			
13	Adjusted Annual Rate ($/MW/Yr)	(line 10 / line 11)	22,436.90	**$23,232.10**	**$795.20**			
			Peak Rate Total					Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	33,115.70					33,115.70
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	2,759.64					2,759.64
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	636.84					636.84
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	127.37					90.98
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	7.96					3.78

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Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)	44,157,831	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,387,609,306	TP	1.00000	1,387,609,306
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	4,585,334,757	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	406,818,923	WS	0.05961	24,251,802
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	0.05961	-
6	TOTAL GROSS PLANT (sum lines 1-5)		6,423,920,817	GP=	23.061%	1,411,861,108
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	20,711,040	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	372,617,994	TP	1.00000	372,617,994
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	1,410,141,577	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	278,481,191	WS	0.05961	16,601,172
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	0.05961	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,081,951,802			389,219,166
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	23,446,791			
14	Transmission	(line 2- line 8)	1,014,991,312			1,014,991,312
15	Distribution	(line 3 - line 9)	3,175,193,180			
16	General & Intangible	(line 4 - line 10)	128,337,731			7,650,631
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		4,341,969,014	NP=	23.552%	1,022,641,942
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 3, Col. 1 (Notes C, F, Y)	-	NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 3, Col. 2 (Note C, F, Y)	(319,680,605)	DA	1.00000	(319,680,605)
21	Account No. 283 (enter negative)	Attachment 5, Line 3, Col. 3 (Notes C, F, Y)	(11,663,397)	DA	1.00000	(11,663,397)
22	Account No. 190	Attachment 5, Line 3, Col. 4 (Notes C, F, Y)	7,459,781	DA	1.00000	7,459,781
23	Account No. 255 (enter negative)	Attachment 5, Line 3, Col. 5 (Notes C, F, Y)	(1,982,947)	DA	1.00000	(1,982,947)
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 6, Col. 6 (Notes C & Y)	-	DA	1.00000	-
25	Unfunded Reserve Labor-related (enter negative)	Attachment 14, Line 9, Col. 6 (Notes C & Y)	-	DA	1.00000	-
26	CWIP	216.b (Notes X & Z)	-	DA	1.00000	-
27	Unamortized Regulatory Asset	Attachment 16a, 16b, 16c, Line 15, Col. 7 (Note X)	25,800,648	DA	1.00000	25,800,648
28	Unamortized Abandoned Plant	Attachment 17, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
29	TOTAL ADJUSTMENTS (sum lines 19-28)		(300,066,519)			(300,066,519)
30	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)	-	TP	1.00000	-
31	WORKING CAPITAL (Note H)					
32	CWC	1/8*(Page 3, Line 15 minus Page 3, Lines 11 & 12)	10,876,876			3,374,339
33	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)	-	TE	0.94480	-
34	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)	1,649,218	GP	0.23061	380,328
35	TOTAL WORKING CAPITAL (sum lines 32 - 34)		12,526,094			3,754,667
36	RATE BASE (sum lines 18, 29, 30, & 35)		4,054,428,589			726,330,090

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2017

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b	25,133,908	TE	0.94480	23,746,587
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		-	DA	1.00000	-
3	Less Account 565	321.96.b	-	DA	1.00000	-
4	Less Account 566	321.97.b	(7,913,701)	DA	1.00000	(7,913,701)
5	A&G	323.197.b	62,349,851	W/S	0.05961	3,716,878
6	Less FERC Annual Fees		-	W/S	0.05961	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		-	W/S	0.05961	-
8	Plus Transmission Related Reg. Comm. Exp. (Note I)		-	TE	0.94480	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 9 (Note C)	(468,750)	DA	1.00000	(468,750)
10	Common	356.1	-	CE	0.05961	-
11	Account 407.3 Amortization of Regulatory Assets	Attachment 16a, 16b, 16c, Line 15, Col. 5	5,368,533	DA	1.00000	5,368,533
12	Account 566 Amortization of Regulatory Assets		-	DA	1.00000	-
13	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 12	(7,913,701)	DA	1.00000	(7,913,701)
14	Total Account 566 (sum lines 12 & 13, ties to 321.97.b)		(7,913,701)			(7,913,701)
15	TOTAL O&M (sum lines 1, 5,8, 9, 10, 11, 14 less 2, 3, 4, 6, 7)		92,383,542			32,363,249
	DEPRECIATION AND AMORTIZATION EXPENSE					
16	Transmission	336.7.b (Note U)	30,076,277	TP	1.00000	30,076,277
17	General & Intangible	336.1.f & 336.10.f (Note U)	16,201,290	GP	0.05961	965,812
18	Common	336.11.b (Note U)	-	CE	0.05961	-
19	Amortization of Abandoned Plant	Attachment 17, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
20	TOTAL DEPRECIATION (sum lines 16 -19)		46,277,567			31,042,089
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
21	Payroll	263.i (Attachment 7, line 1z)	10,835,432	W/S	0.05961	645,935
22	Highway and vehicle	263.i (Attachment 7, line 2z)	8,096	W/S	0.05961	483
23	PLANT RELATED					
24	Property	263.i (Attachment 7, line 3z)	6,023,392	GP	0.23061	1,389,060
25	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
26	Other	263.i (Attachment 7, line 5z)	3,618	GP	0.23061	834
27	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	0.23061	-
28	TOTAL OTHER TAXES (sum lines 21 - 27)		16,870,538			2,036,312
	INCOME TAXES	(Note K)				
29	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.85%			
30	CIT=(T/1-T) * (1-(WCLTD/R)) =		38.47%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
31	1 / (1 - T) = (from line 30)		1.6906			
32	Amortized Investment Tax Credit (266.8.f) (enter negative)		(131,199)			
33	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) [Notes D & Y]		1,640,804			
34	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) [Notes E & Y]		-			
35	Income Tax Calculation = line 30 * line 40		121,925,332	NA		21,842,298
36	ITC adjustment (line 31 * line 32)		(221,807)	NP	0.23552	(52,241)
37	Permanent Differences and AFUDC Equity Tax Adjustment (line 31 * line 33)		2,773,971	DA	1.00000	2,773,971
38	(Excess)/Deficient Deferred Income Tax Adjustment (line 31 * line 34)		-	DA	1.00000	-
39	Total Income Taxes	sum lines 35 through 38	124,477,495			24,564,028
40	RETURN [Rate Base (page 2, line 36) * Rate of Return (page 4, line 25, col. 6)]		316,900,098.71	NA		56,771,028
41	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE) (sum lines 15, 20, 28, 39, 40)		596,909,241			146,776,705
42	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)	0			0
43	GROSS REV. REQUIREMENT (line 41 + line 42)		596,909,241			146,776,705

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SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total transmission plant (page 2, line 2, column 3)						1,387,609,306		
2	Less transmission plant excluded from ISO rates (Note M)						-		
3	Less transmission plant included in OATT Ancillary Services (Note N)						-		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,387,609,306		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (page 3, line 1, column 3)						25,133,908		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,387,321		
8	Included transmission expenses (line 6 less line 7)						23,746,587		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.94480		
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.94480		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	-	0.00	-				
13	Transmission	354.21.b	3,518,540	1.00	3,518,540				
14	Distribution	354.23.b	37,236,683	0.00	-		W&S Allocator		
15	Other	354.24,25,26.b	18,267,549	0.00	-		($ / Allocation)		
16	Total (sum lines 12-15)		59,022,772		3,518,540	=	0.05961	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)								
			$		% Electric		W&S Allocator		
17	Electric	200.3.c	-		(line 17 / line 20)		(line 16, col. 6)		CE
18	Gas	201.3.d	-		1.00000	*	0.05961	=	0.05961
19	Water	201.3.e	-						
20	Total (sum lines 17 - 19)		-						
	RETURN (R)						$		
21		Preferred Dividends (118.29c) (positive number)					-		
					Cost				
			$	%	(Note P)		Weighted		
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)		1,815,384,615	60%	0.0573		0.0346	=WCLTD	
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)		-	0%	0.0000		0.0000		
24	Common Stock Attachment 8, Line 14, Col. 6) (Note X)		1,189,489,334	40%	0.1100		0.0435		
25	Total (sum lines 22-24)		3,004,873,949				0.0782	=R	
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)					
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						-		
27	b. Bundled Sales for Resale included in Divisor on page 1						-		
28	Total of (a)-(b)						-		
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)			(300.17.b)			-		
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			(300.19.b)			-		
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)			(330.x.n)			1,074,828		

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Jersey Central Power & Light

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT.
B	Prepayments shall exclude prepayments of income taxes.
C	Transmission-related only
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Amounts to be included will be January 1, 2017 and thereafter.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 15, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
K	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 31).

Inputs Required:	FIT =	35.00%	
	SIT=	9.00%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test.
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = Attachment 10, Column (j) total. Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Q	Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by it own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.

Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated on this 18th day of November, 2016.

/s/ *Stephen C. Pearson*
Stephen C. Pearson

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