dividend, the Attorney General multiplied the expected dividend for the coming quarter by four and multiplied the result by one half of the expected growth rate (Exh. AG-JRW-1, at 41-42).

In developing the expected growth rate, the Attorney General relies on the historic and projected growth rates of EPS, dividends per share, and book value per share provided by Value Line and the EPS growth forecasts of Wall Street analysts provided by Yahoo, First Call, and Zacks (Exhs. AG-JRW-1, at 42; AG-JRW-10, at 3-6). Although the Attorney General assumes that EPS and dividends per share will exhibit similar growth rates over the very long term, she relies on historic and projected dividends per share and book value per share as well as internal growth to balance what she states are the shortcomings of relying solely on EPS as a proxy (i.e., an upward bias among Wall Street analysts) (Exhs. AG-JRW-1, at 46-47; AG-JRW-10, at 3-6). The DCF projected growth rate for her proxy and the Company's proxy group is 4.75 percent and 5.0 percent, respectively (Exhs. AG-JRW-1, at 50-51; AG-JRW-10, at 1, 3-6). The Attorney General chose the midpoint of this range or 4.875 percent as the DCF growth rate for her proxy group and the Company's proxy group (Exhs. AG-JRW-1, at 51; AG-JRW-10, at 1, 3-6)

The Attorney General added the adjusted dividend yields and the estimated growth rates to determine a cost of equity for both her proxy group and the Company's proxy group (Exhs. AG-JRW-1, at 51; AG-JRW-10, at 1). The DCF analysis performed by the Attorney General yields a cost of equity of 8.77 percent and 8.82 percent for her proxy group and the Company's proxy group, respectively (Exhs. AG-JRW-1, at 51; AG-JRW-10, at 1).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that her DCF-estimated cost of equity at the lowest end of her range of 7.8 percent appropriately supports her proposed ROE for National Grid (Attorney General Brief at 126, citing D.T.E. 02-24/25 at 231; Attorney General Reply Brief at 60). The Attorney General contends that her proposal takes into account the Company's issues associated with a split test year and depreciation accounting (Attorney General Brief at 126; Attorney General Reply Brief at 60).

The Attorney General asserts that the Department should reject National Grid's DCF analysis for several reasons. First, the Attorney General argues that the Company's analysis has given little weight to its constant growth DCF results, claiming that utility price-earnings ("P/E") ratios have increased, and are now high on both on an absolute and relative level (Attorney General Brief at 110; Attorney General Reply Brief at 62).

Second, the Attorney General contends that the Company's GDP growth rate of 5.23 percent used in its multi-stage DCF model is excessive, unsupported by theoretical or empirical evidence, not reflective of economic growth in the United States, and about 100 basis points above projections of long-term GDP growth (Attorney General Brief at 109-110, citing Exh. AG-JRW-1, at 68). The Attorney General claims that despite some fluctuations, nominal GDP growth rates have declined over the years and have been in the 3.50 percent to four percent range over the past five years (Attorney General Brief at 112, citing Exh. AG-JRW-1, at 73). Further, she argues that the compounded GDP growth rate of 6.63 percent over the 50 years since the mid-1960s belies a "monotonic and significant" decline in nominal GDP growth rates in recent decades (Attorney General Brief at 112, citing Exh. AG-JRW-1, at 73). Therefore, the Attorney General concludes that a more appropriate nominal GDP growth rate figure for today's economy is in the range of four to five percent (Attorney General Brief at 112-113).

Finally, the Attorney General argues that the Company's DCF analyses are inconsistent in their use of historic versus projected data (Attorney General Brief at 114, citing Exh. AG-JRW-1, at 75-77). In particular, the Attorney General contends that in developing its constant growth DCF analysis, the Company ignored data on historical EPS, dividends per share, and book value per share, relying solely on what she considers to be inflated long-term EPS growth rate projections of Wall Street analysts and Value Line (Attorney General Brief at 114, citing Exh. AG-JRW-1, at 75-77; Attorney General Reply Brief at 63). In addition, the Attorney General claims that, in developing a terminal DCF growth rate for its multi-stage growth DCF analysis, the Company ignored well known, long-term real GDP growth rate forecasts (Attorney General Brief at 112, citing Exh. AG-JRW-1, at 75-77; Attorney General Reply Brief at 63).

ii. Company

National Grid argues that the Attorney General's DCF calculation is subjective and incapable of replication (Company Brief at 142, citing Exh. NG-RBH-Rebuttal-1, at 24, 38; Company Reply Brief at 48). In addition, the Company contends that Attorney General's DCF recommendation improperly relies on dividend per share and book value per share growth rates, which it contends are merely derivative of earnings growth (Company Brief at 142, citing Exh. NG-RBH-Rebuttal-1, at 34-38).

The Company disputes the Attorney General's claim that it gave insufficient weight to the results of its constant-growth DCF analysis (Company Brief at 142). Instead, the Company claims that what appears to be the issue is the Attorney General's refusal to even consider a multi-stage DCF model in setting a ROE, despite the limiting assumptions underlying the constant-growth DCF model such as the assumption that the P/E ratio stays constant in perpetuity (Company Brief at 142-143, citing Exh. NG-RBH-1, at 24). The Company adds that with P/E ratios for utilities currently at unusually high levels, it is necessary to give consideration to the result of the multi-stage DCF model when determining an appropriate level of ROE (Company Brief at 143, citing Exh. RBH-1-Rebuttal-1, at 23).

In addition, National Grid dismisses the Attorney General's contention that the EPS growth rate estimates relied on by the Company were biased (Company Brief at 143). First, the Company asserts that litigation and new financial regulations in 2003 helped neutralize analysts' conflicts of interest while removing bias in the median forecast errors (Company Brief at 143, citing Exh. NG-RBH-Rebuttal-1, at 30-31). Second, the Company maintains that the Department also has noted a lack of pronounced bias in the EPS forecasts for utilities (Company Brief at 143, citing Exh. NG-RBH-Rebuttal-1, at 30-31; D.P.U. 13-75, at 302). Third, the Company maintains that regardless of analysts' forecasts, investor expectations are more important when applying the DCF model, and the DCF-estimated ROE must recognize and reflect that it is the EPS growth rate expectations of investors that drive stock prices, even if influenced by analysts' forecasts (Company Brief at 143, citing Exh. NG-RBH-Rebuttal-1, at 20-22). Further, the Company notes that the Attorney General conceded that any bias that may exist for utilities is at most in the range of 20 basis points (Company Brief at 143, citing Tr. 14, at 1562).

National Grid also disputes the Attorney General's assertion that the Company's proposed multi-stage DCF growth rate of 5.23 percent, based on GDP growth rate, is inappropriate because such a growth rate does not take into consideration the more recent lower trends in GDP growth or the current forecasts by economists and some federal agencies (Company Brief at 144, citing Attorney General Brief at 111-114). To support its position that its GDP-derived growth rate is appropriate, National Grid notes that the annual nominal GDP growth rate has remained relatively stable since 1990 and was greater than five percent in twelve of the last 26 years (Company Brief at 144).

Further, the Company argues that its proposed long-term growth rate is consistent with other respected economic forecasts on long-term growth (Company Brief at 144). In support of its position, National Grid asserts that a 2010 report issued by McKinsey & Company ("McKinsey Report"), relied upon by the Attorney General in developing her testimony, states that "…long-term earnings growth for the market as a whole is unlikely to differ significantly from growth in GDP" (Company Brief at 144; Company Reply Brief at 52). In the same report, according to the Company, it also is noted that "'[r]eal GDP has averaged 3 to 4 percent over [the] past seven or eight decades, which would indeed be consistent with nominal growth of 5 to 7 percent given current inflation of 2 to 3 percent" (Company Brief at 144; Company Reply Brief at 52). Therefore, the Company maintains that its proposed growth rate of 5.23 percent is supported by the McKinsey Report because its selected growth rate represents a combination of historical real GDP growth rate and a corresponding level of expected inflation, and falls within the lower end of the five to seven percent range noted by the McKinsey Report (Company Brief at 144; Company Reply Brief at 52). Further, the Company argues that the Attorney General has not shown that the forecasts she cites are actually relied upon by investors, nor has she explained why she considers economists' near-term interest rate projections are improper while at the same time accepting their long-term real GDP growth rate projections (Company Brief at 144).

Finally, the Company maintains that it has addressed the Attorney General's concerns regarding the appropriate P/E ratio to be used in the DCF analysis by providing an additional set of multi-stage DCF scenarios that calculate the terminal values of the stocks of the companies in the proxy group using a constant average P/E ratio of 18.56 percent (Company Brief at 144-145; Exh. NG-RBH-Rebuttal-4). According to the Company, using a range of multi-stage DCF scenarios with a constant average P/E ratio fully support the Company's proposed 10.50 percent ROE (Company Brief at 145, citing Exh. NG-RBH-Rebuttal-4).

d. Analysis and Findings

In developing their proposed ROEs, both the Company and the Attorney General use a form of the DCF model that assumes an infinite investment horizon and a constant growth rate (Exhs. NG-RBH-1, at 18, 20; AG-JRW-1, at 38). This model has a number of very strict assumptions (e.g., the infinite investment horizon and dividend growth at a constant rate in perpetuity) (Exh. NG-RBH-1, at 20). These assumptions affect the estimates of the cost of equity. D.P.U. 10-114, at 312; D.P.U. 09-39, at 387.

Because regulation establishes a level of authorized earnings for a utility that, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. D.P.U. 10-114, at 312; D.P.U. 10-55, at 512; D.P.U. 09-30, at 357-358. Specifically, the DCF model includes an element of circularity when applied in a rate case because investors' expectations depend upon regulatory decisions. D.P.U. 10-70, at 253; D.P.U. 09-30, at 357-358. Consequently, this circularity affects the results of both the Company's and the Attorney General's DCF models. The Attorney General's DCF model places less emphasis on analyst forecasts of EPS growth rates which, to some extent, compensates for this circularity (see Exh. AG-JRW-1, at 46-47).

The Company and Attorney General use different data sources to estimate the dividend yield and growth rates (Exhs. NG-RBH-1, at 18-19; AG-JRW-1, at 36-46). The Company uses the Bloomberg Professional ("Bloomberg") dividend estimates, adjusting them by one-half of the growth rate, while the Attorney General calculates the dividend yield by applying one-half of the growth rate to a six-month average dividend yield (Exhs. NG-RBH-1, at 19; NG-RBH-3; AG-JRW-1, at 42, 51; AG-JRW-10, at 1). The Department finds that both the Company's and the Attorney General's approaches are logical and reasonable. Further, there is no evidence to establish that investors rely overwhelmingly on one approach over the other. Therefore, we find that both approaches provide a credible basis for evaluating a determination of the Company's allowed ROE.

In addition, the Company and the Attorney General use different growth rates in their respective DCF analyses (Exhs. NG-RBH-1, at 29-30; NG-RBH-4; NG-RBH-Rebuttal 4; AG-JRW-1, at 50-51; AG-JRW-10, at 1). Determining the appropriate long-term growth expectations of investors in a DCF analysis can be difficult and controversial (see Exhs. NG-RBH-1, at 20; AG-JRW-1, at 39). The Company relies on a forward looking growth analysis using EPS, based on the assumption that investors form their investment decisions based on expectations of growth in earnings and not dividends (Exhs. NG-RBH-1, at 22; NG-RBH-Rebuttal-1, at 38; NG-RBH-Rebuttal-2). Conversely, the Attorney General bases her growth rate on a historical and forward looking growth analysis using EPS, dividends per share, book value per share, and retention growth rates (Exh. AG-JRW-1, at 42-44). The Attorney General emphasizes dividend growth over earnings growth because of the alleged upward bias of forecasts by financial analysts (Exhs. AG-JRW-1, at 46-47; AG-JRW-10, at 3, 4, 5). The Department has found that investors' heavy reliance on EPS forecasts give credence to the Attorney General's argument that investors are aware of upward biases. D.P.U. 13-75, at 302. Accordingly, the Department will take these biases into consideration in evaluating the Company's DCF analysis.

4. Capital Asset Pricing Model

a. Company Proposal

The Company used the CAPM to estimate the cost of equity for its proxy group (Exhs. NG-RBH-1, at 31; NG-RBH-5; NG-RBH-6; NG-RBH-7). The application of the Company's CAPM resulted in eight individual costs of equity estimates, ranging from 9.46 percent to 11.17 percent (Exhs. NG-RBH-1, at 34, 63; NG-RBH Rebuttal-1, at 76; NG-RBH- Rebuttal-7). National Grid considered these results when determining its proposed ROE (Exhs. NG-RBH-1, at 6; NG-RBH-Rebuttal-7).

The CAPM is a market-based investment model based on capital markets theory and modern portfolio theory. In the CAPM, the required rate of return on common equity is equal to the expected risk free rate of return plus a premium for the implicit systematic risk of the security (Exh. NG-RBH-1, at 31). There are three necessary components to calculate the cost of equity in the CAPM: (1) an expected risk free rate of return; (2) the market risk premium; and (3) the beta, a measure of systematic risk (Exhs. NG-RBH-1, at 31; NG-RBH-5; NG-RBH-6; NG-RBH-7).

The Company used the current and forecasted 30-year Treasury bond yields to arrive at current, near-term, and long-term risk free rates (Exhs. NG-RBH-1, at 32; NG-RBH-5; NG-RBH-6; NG-RBH-7). The CAPM market risk premium is derived from the total return on the overall market minus the risk free rate of return. The Company developed ex ante market risk premiums based on data from both Bloomberg and Value Line by calculating their respective estimated market required returns less the Treasury bond yield (Exhs. NG-RBH 1, at 32-33; NG-RBH-5; NG-RBH-7).

The Company obtained beta coefficients for its proxy group from Bloomberg (0.653) and Value Line (0.75) (Exhs. NG-RBH-1, at 33; NG-RBH-6). Using these beta coefficients in combination with separate Bloomberg and Value Line data and current, near term, and long-term risk free rates, National Grid calculated four Bloomberg market DCF derived CAPM results and four Value Line market DCF derived CAPM results (Exhs. NG-RBH-1, at 34; NG-RBH-7).

b. Attorney General Proposal

The Attorney General used a traditional CAPM approach in which the cost of equity is equal to the sum of the interest rate on risk free bonds and an equity risk premium (i.e., the excess return that an investor expects to receive above the risk-free rate for investing in stocks) (Exhs. AG-JRW-1, at 52; AG-JRW-11, at 1). The Attorney General's CAPM analysis resulted in a cost of equity of 8.10 percent (Exhs. AG-JRW-1, at 58; AG-JRW-11, at 1).

In her analysis, the Attorney General used the upper bound of the six-month average yield on 30-year Treasury bonds (i.e., four percent) as the risk free rate (Exhs. AG-JRW-1, at 54; AG-JRW-11). The Attorney General then calculated an estimated market risk premium of 5.5 percent, based on the midpoint of a range of market risk premiums of four percent to six percent (Exhs. AG JRW-1, at 59; AG-JRW-11, at 1, 5 6). To calculate the beta coefficient, the Attorney General performed a regression analysis of the returns of the companies in her proxy group against the return of the S&P 500 representing the market, resulting in a median beta coefficient of 0.75 percent (Exhs. AG-JRW-1, at 61; AG-JRW-11, at 1, 3). The Attorney General multiplied the estimated market risk premium of 5.5 percent by the beta coefficients of 0.75 percent to produce an expected equity risk premium of 4.10 percent (see Exhs. AG-JRW-1, at 61; AG-JRW-11, at 1). The risk free rate of four percent added to the expected risk premiums of 4.10 percent results in a cost of equity of 8.10 percent (see Exhs. AG-JRW-1, at 58; AG-JRW-11, at 1).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company's CAPM analysis produces results that vastly overstate long-term growth projections (Attorney General Brief at 119). According to the Attorney General, the Company's primary errors are with its use of inflated market risk premiums of 10.05 percent and 10.59 percent (Attorney General Brief at 120). Further, the Attorney General contends that the Company's long-term EPS growth rates of 11.12 percent and 10.80 percent are based on overly optimistic and upwardly biased Wall Street analysts' forecasts (Attorney General Brief at 117-119 citing Exh. AG-JRW-1, at 79-80).

In contrast, the Attorney General maintains that long-term economic, earnings, and dividend growth rates in the United States indicate that historical long-term growth rates are in the five percent to seven percent range (Attorney General Brief at 118). Moreover, the Attorney General asserts that more recent trends suggest lower future economic growth than the long-term historic GDP growth, in the range of four percent to five percent for today's economy, and notes that the projected long-term GDP growth rate forecasts by economists and government agencies are currently in the four percent to five range as well (Attorney General Brief at 118, citing Exh. AG-JRW-1, at 73-75).

Finally, the Attorney General argues that given current low inflation and limited economic growth, the Company's projected earnings growth rates, implied expected stock market returns, and equity risk premiums are not indicative of the realities of the economy (Attorney General Brief at 119, citing Exh. AG-JRW-1, at 80). Based on the above, the Attorney General asserts that the Department should reject the Company's proposed CAPM analysis and recommendations (Attorney General Brief at 120).

ii. Company

The Company argues that the Attorney General's CAPM calculation must be rejected because the equity risk premium she relied on assumes market returns that do not make theoretical or practical sense (Company Brief at 145, citing Exh. NG-RBH-Rebuttal-1, at 54). Further, the Company contends that the Attorney General's CAPM analyses do not reflect fundamental risk-return relationships (Company Brief at 145).

Finally, the Company dismisses the Attorney General's claim that reliance on analysts' forecasts invalidates the Company's CAPM approach (Company Brief at 168). Using the same analysis as discussed above regarding the DCF model, the Company maintains that recent evidence does not support any upward bias in analysts' forecasts in particular for electric utilities (Company Brief at 145, citing Exh. NG-RBH-Rebuttal-1, at 34).

d. Analysis and Findings

The Department has previously found that the traditional CAPM as a basis for determining a utility's cost of equity has limited value because of a number of questionable assumptions that underlie the model. D.P.U. 10-114, at 318; D.P.U. 10-70, at 270; D.P.U. 08-35, at 207; D.T.E. 03-40, at 359-360; D.P.U. 956, at 54. For example, the Department has not been persuaded that long-term government bonds are the appropriate proxy for the risk free rate and has found that the coefficient of determination for beta is generally so low that the statistical reliability of the results is questionable. D.T.E. 01-56, at 113; D.P.U. 93-60, at 256-257; D.P.U. 92-78, at 113; D.P.U. 88-67 (Phase I) at 182-184.

The Attorney General's CAPM analysis employs a risk free rate of four percent, using the upper bound of the prior six months' 30-year Treasury bond rates as a proxy (Exh. AG-JRW-1, at 54, 60-61). Current federal monetary policy that is intended to stimulate the economy has pushed treasury yields to near historic lows (Exh. AG-JRW 1, at 21-22). Consequently, the Department has found that a CAPM analysis based on current treasury yields may tend to underestimate the risk free rate over the long term and, thereby, understate the required ROE. D.P.U. 14-150, at 350; D.P.U. 12-25, at 427; D.P.U. 11 01/D.P.U. 11-02, at 416.

The Company develops a range of risk free rates from 2.68 percent to 3.35 percent, relying on the current 30-year Treasury bond rates as published in Bloomberg, as well as the near- and long-term projected 30-year Treasury bond rates based on interest rate forecasts published in Blue Chip Financial Forecasts (Exhs. NG-RBH-Rebuttal-1, at 75; NG-RBH-Rebuttal-7). The CAPM is based on investor expectations and, therefore, it is appropriate to use a prospective measure for the risk-free rate component. The Department has found that Blue Chip Financial Forecasts is widely relied on by investors and provides a useful proxy for investor expectations for the risk-free rate. D.P.U. 13-75, at 314.

The Attorney General calculated a market risk premium of 5.5 percent, based on her analysis of numerous surveys of financial professionals, including financial forecasters, chief financial officers, and academics (Exhs. AG-JRW-1, at 59-60; AG-JRW-11, at 1). Alternatively, the Company calculates a revised market risk premium range of 8.46 percent to 11.62 percent based on DCF analyses (Exhs. NG-RBH-Rebuttal-1, at 76; Sch. NG-RBH-Rebuttal-7). Because the CAPM is considered an ex-ante, forward looking model that recognizes that investors are generally risk averse and will demand higher returns in exchange for assuming higher levels of investment risk, the Department finds that the Company's approach based on DCF analyses is less reliable than the survey results of financial professionals. D.P.U. 13-90, at 225-226; D.P.U. 13-75, at 314.

The Company asserts that because investors rely on financial analysts' forecasts in making investment decisions EPS forecasts are superior to other measures of growth in predicting stock prices (see Exh. NG-RBH-1, at 21). The Department notes that a 2015 survey of over 8,000 academics, financial analysts, and companies estimates a market risk premium of 5.5 percent, which is far lower than the 8.46 percent to 11.62 percent range used in National Grid's analysis (Exhs. NG-RBH-Rebuttal-1, at 76; NG-RBH-Rebuttal-7; AG-JRW-1, at 58;

AG-JRW-11, at 6). Accordingly, the Department places more weight on the Attorney General's approach to developing a market risk premium.

Based on the above considerations, the Department will place limited weight on the results of the respective CAPM estimates in determining the appropriate ROE. Based on the above considerations, to the limited extent that we rely on CAPM estimates, the Department gives more weight to the Attorney General's proposed CAPM.

5. Risk Premium Model

a. Company Proposal

The risk premium model is based on the concept that investing in common stock is riskier than investing in debt and, therefore, investors require a higher rate of return for equity (Exh. NG-RBH-1, at 34).[267] In the bond yield plus risk premium model used by the Company, the cost of equity is derived by calculating a risk premium over the returns available to bondholders (Exh. NG-RBH-1, at 34). Based on data from 1,456 electric utility proceedings between January 1, 1980 and September 30, 2015, the Company derived a risk premium analysis producing a cost of equity range of 10.05 percent to 10.59 percent applicable to its proxy group (Exh. NG-RBH-8).

National Grid calculated the risk premium as the difference between: (1) actual authorized returns using data from 1,456 electric utility rate proceedings between January 1,

267 The equity risk premium is defined as the incremental return that an equity investment provides over the risk-free rate (Exhs. NG-RBH-1, at 34; NG-RBH-8). The risk premium method of determining the cost of equity recognizes that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. The general approach is relatively straightforward: (1) determine the historical spread between the return on debt and the ROE; and (2) add this spread to the current debt yield to derive an estimate of current equity return requirements. D.P.U. 13-75, at 316 n.201.

1980, and September 30, 2015; and (2) the then prevailing long-term Treasury yield (i.e., 30-year bonds) (Exhs. NG-RBH-1, at 35; NG-RBH-8). To account for the forward looking return and interest rates, National Grid calculated the average return period between the filing of this case and the approval of rates, as well as the level of interest rates during the pendency of the proceedings (Exh. NG-RBH-1, at 35). To assess the relationship between the 30-year Treasury yield and the equity risk premium, the Company relied on a statistical analysis that concluded there was a statistically significant inverse relationship between the 30-year Treasury yield and the equity risk premium (Exhs. NG-RBH-1, at 36-37; NG-RBH-8).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Company's application of the bond yield plus risk premium model is flawed for three reasons (Attorney General Brief at 120). First, the Attorney General argues that the Company's method produces an inflated measure of the risk premium because it is based on historic authorized ROEs less Treasury yields, and then is applied to projected Treasury yields that always are forecasted to increase (Attorney General Brief at 121). Second, the Attorney General contends that the Company's overall approach improperly uses authorized ROEs as an input to the model, and that such an approach is more of a gauge of public utility commission behavior than a consideration of investor behavior (Attorney General Brief at 121, citing Exh. AG-JRW-1, at 83-84). In this regard, the Attorney General claims that in setting ROEs, regulatory commissions evaluate capital market data such as dividend yields, expected growth rates, interest rates, as well as rate case specific regulatory information (Attorney General Brief at 121, citing Exh. AG-JRW-1, at 83-84). Further, the Attorney General argues that the Company's analysis overstates the risk premium because National Grid estimates the risk premium using historical interest rate data, and then applies this data to forecasted interest rates (Attorney General Brief at 121, citing Exh. AG-JRW-1, at 82).

Finally, the Attorney General argues that a comparison of the Company's risk premium results to actual authorized ROEs for electric utility companies confirms the errors in the Company's approach (Attorney General Brief at 122, citing Exh. JRW-Rebuttal-1, at 16-20). The Attorney General notes that authorized ROEs for electric distribution companies have decreased in recent years, from 10.01 percent in 2012, to 9.8 percent in 2013, to 9.76 percent in 2014, and 9.58 percent in 2015 (Attorney General Brief at 122, citing Exh. JRW-Rebuttal-1, at 16-20). Moreover, the Attorney General asserts that National Grid's long-term projected Treasury bond yield of 4.9 percent is 200 basis points above current yields and, therefore, is not reasonable (Attorney General Brief at 121, citing Exh. JRW-1, at 82).

ii. Company

National Grid disputes the Attorney General's argument that the Company's bond yield plus risk premium approach gauges regulatory commission behavior rather than investor behavior (Company Brief at 146-147). The Company argues that regulatory decisions reflect market based analyses (Company Brief at 147, citing Exh. NG-RBH-Rebuttal-1, at 57). Further, the Company contends that because authorized returns are publicly available, such data are to some degree reflected in investors' return expectations and requirements. For these reasons, the Company asserts that authorized returns are a reasonable measure of investor required returns (Company Brief at 147, citing Exh. NG-RBH-Rebuttal-1, at 57).

The Company notes that in the past the Department has viewed the risk premium approach as a "supplemental approach" in determining the level of ROE (Company Brief at 147, citing D.P.U. 07-71, at 137). Based on the above, National Grid argues that the Department should at least supplement its calculation of the Company's ROE with the risk premium approach (Company Brief at 147).

c. Analysis and Findings

The Department has repeatedly found that an equity risk premium analysis can overstate the amount of company-specific risk and, therefore, the cost of equity. See D.P.U. 10-114, at 322; D.P.U. 88-67 (Phase I) at 182-184. More specifically, the Department has found that the return on long-term corporate or public utility bonds may have risks that could be diversified with the addition of common stock in investors' portfolios and, therefore, the risk premium model overstates the risk accounted for in the resulting cost of equity. D.P.U. 10-114, at 322; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. Nonetheless, the Department has acknowledged the value of the risk premium model as a supplemental approach to other ROE models. D.P.U. 10-114, at 322; D.P.U. 07-71, at 137; D.T.E. 99-118, at 85-86.

In the instant case, the Company's risk premium analysis is flawed. First, the Department has recognized the circularity inherent in the use of authorized utility returns to derive the risk premium. D.P.U. 13-75, at 319; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. In addition, the Department has criticized the use of corporate bond yields in determining the base component of the risk premium analysis, and we are not convinced that the Company's substitution of projected Treasury debt yields provides a better approach. D.P.U. 09-39, at 388-389; D.P.U. 08-35, at 202; D.P.U. 90-121, at 171. The Company continues to use projected cost of Treasury debt in this model, suggesting that the risk premium approach is forward-looking and, therefore, using the forward-looking approach is appropriate (see Exh. NG-RBH-8). The Department disagrees. The risk premium model is not a forward looking approach, and is, instead, based on current market conditions. See D.P.U. 13-75, at 319; D.P.U.12-25, at 433. Accordingly, the Department finds that current treasury yields are more appropriate than projected yields for use in a risk premium analysis. For these reasons, the Department finds that National Grid's risk premium model overstates the required ROE for the Company.

E. Conclusion

The standard for determining the allowed ROE is set forth in Bluefield at 692-693 and Hope at 603. The allowed ROE should preserve a company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. See Bluefield at 692-693; Hope at 603, 605. The allowed ROE should be determined "having regard to all relevant facts." Bluefield at 692.

The Company recommends that the Department approve an ROE of 10.50 percent (Exhs. NG-RBH-1, at 3; NG-RBH-Rebuttal-1, at 77). The Attorney General recommends an ROE of 7.80 percent (Attorney General Brief at 125-126, citing Exh. JRW-1, at 61-62). The Department has found that both quantitative and qualitative factors must be taken into account in determining an allowed ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase I) at 224-225.; see also Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 11, cert. denied, 439 U.S. 921 (1978); Boston Gas Company v. Department of Public Utilities, 359

Mass. 292, 305-306 (1971).[268] Thus, in determining an appropriate ROE for National Grid, the Department first evaluates the quantitative factors presented in this case.

In support of its recommended ROE, National Grid has presented quantitative analyses using the DCF model, the CAPM, and a bond yield plus risk premium approach, each incorporating the financial data of its proxy group. The Attorney General has presented her analyses using the DCF model and the CAPM, incorporating the financial data of both her proxy group and the Company's proxy group (Exh. AG-JRW-4, Panels A and B). The use of empirical analyses in this context is not an exact science. A number of judgments are required in conducting a model based rate of return analysis. Even in studies that purport to be mathematically sound and highly objective, crucial subjective judgments are made along the way and necessarily influence the end result. D.P.U 18731, at 59. Each level of judgment to be made in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

As discussed above, the evidence demonstrates that each equity cost model used by the Company and the Attorney General suffers from a number of simplifying and restrictive assumptions. Applying them to the financial data of a proxy group of companies could provide results that may not be reliable for the purpose of setting the Company's ROE. For example, we

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268 As noted above, the Attorney General proposes a ROE of 7.80 percent to account for what she identifies as a number of Company shortcomings, including its failures to: (1) conform to the Department's explicit instructions regarding the use of a split test year; (2) appropriately account for salvage value, thereby overstating the revenue requirement both in this case and the Company's previous rate case, as well as in the capital tracker mechanism; and (3) remove retired plant from plant in service accounts, resulting in an overstated depreciation expense requirement (Attorney General Brief at 125-126, citing D.T.E. 02-24/25, at 231). As discussed in Sections III and VIII.E, we decline to adjust the ROE based on these specific recommendations.

note the limitations of the DCF models used by both the Company and the Attorney General, including the simplifying assumptions that underlie the constant growth form of the model, and its element of circularity, as well as the inherent limitations in comparing the Company to publicly traded companies. In particular, we find that the Company's DCF analysis overestimates the cost of equity by minimizing the low-outlier estimates. We also find that the Attorney General's DCF model retains some elements of circularity because investor expectations depend upon regulatory decisions.

The Department further finds that the CAPM analyses relied upon by the Company and the Attorney General also are flawed because of the simplifying assumptions underlying CAPM theory and the subjectivity inevitable in estimating market risk premiums. To the extent we rely on the CAPM estimates, we give more weight to the Attorney General's analysis because the magnitude of the deficiencies within the Company's proposed CAPM, including the estimate of a market risk premium, is greater. Finally, we find that the Company's risk premium approach suffers from a number of limitations and tends to overstate National Grid's required ROE.

While the results of analytical models are useful, the Department must ultimately apply its own judgment to the evidence to determine an appropriate rate of return. We must apply to the record evidence and argument considerable judgment and agency expertise to determine the appropriate use of the empirical results. Our task is not a mechanical or model driven exercise.[269] D.P.U. 08-35, at 219-220; D.P.U. 07-71, at 139; D.T.E. 01-56, at 118;

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269 As the Department stated in New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973):

> Advances in data gathering and statistical theory have yet to achieve precise prediction of future events or elimination of the bias of the

D.P.U. 18731, at 59; see also 375 Mass. 1, 15. The Department must account for additional factors specific to a company that may not be reflected in the results of the models.

We note that a portion of the revenues of the companies in both proxy groups is derived from unregulated and competitive lines of business (Exhs. AG-5-15; AG-JRW-4, at 1; AUS Utilities Reports, passim). All else equal, this mix of regulated and unregulated operations would tend to overstate the proxy groups' risk profiles relative to that of the Company. Therefore, in applying this comparability standard, we will consider such risk differentials when weighing the results of the models used to estimate the Company's allowed ROE.

In addition, the Department granted in this Order revisions to National Grid's CIRM (formerly CapEx), which allows the Company to implement an annual rate adjustment to support the net increase in rate base arising from the annual capital additions that the Company makes to upgrade its distribution system (see Section V.D above). National Grid's CIRM, which now accounts for property tax expense, serves to reduce the Company's risks and its investors' return requirement. Although many companies in both proxy groups employ some form of infrastructure recovery mechanism, these infrastructure recovery mechanisms vary among the companies, particularly insofar as the scope of eligible investments and the timing of cost recovery (Exhs. NG-RBH-1, at 40; NG-RBH-9; AG-JRW-4). On the whole, the infrastructure recovery mechanisms for these companies are less comprehensive than the CIRM (Exhs. NG-RBH-9; AG-JRW-4).

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witnesses in their selection of data. Thus, there is no irrefutable testimony, no witness who has not made significant subjective judgments along the way to his conclusion, and no number that emerges from the welter of evidence as an indisputable "cost" of equity.

The Department also recognizes that the Company's decoupling mechanism reduces the variability of the Company's revenues and, accordingly, reduces its risks and its investors' return requirement. See D.P.U. 09-39, at 398; D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73. Although many companies in both proxy groups employ some form of revenue stabilization or decoupling mechanism, the Department finds that the degree of revenue stabilization varies among the companies and, on the whole, is not as comprehensive as the Company's decoupling mechanism (Exhs. NG-RBH-9; AG-JRW-4).

The Company argues that the pertinent analysis in assessing the impact of decoupling or CIRM on the Company's ROE is not to analyze whether the Company is "less risky" but rather to ascertain whether (1) the effect of the mechanism was to reduce risk below the levels faced by the Company's peers; and (2) investors knowingly reduced their return requirements as a direct consequence of the mechanism (Exh. NG-RBH-1, at 40-42; Company Brief at 139-141). We disagree. While the issue of decoupling and its overall effect on a company's ROE is not a new factor for consideration for the first time in this proceeding, and independent of whether or not investors are keen to compare National Grid's decoupling level of risk vis-à-vis the Company's peers decoupling mechanisms, the fact remains that these mechanisms reduce the variability of the Company's revenues and, accordingly, reduce its risks and its investors' return requirement. D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73.

In considering National Grid's allowed ROE, the Department also takes into account the modifications to the Company's storm fund mechanism. In particular, the Department has raised the cost-per-storm threshold, excluded from storm fund eligibility any single storm event with incremental costs that exceed $30 million, and modified the carrying charge component of the storm fund (see Section VI.D). These modifications are intended to prevent a significant storm fund deficit, provide necessary rate stability for customers, more appropriately reflect the costs associated with the storm fund balance, and help ensure that the storm fund works as intended. The Department recognizes that, on balance, these modifications tend to increase the Company's risk associated with the recovery for storm costs when compared to the storm fund approved in D.P.U. 09-39. In addition, the Department takes into account our allowance of National Grid's recovery of its test year balance of protected hardship account receivables (see Section VIII.J.3). In allowing this recovery, the Department provides for the probability of recovery to avoid an impairment of loss by National Grid through a charge to its income statement that could be required by generally accepted accounting principles. We find that this ratemaking treatment of protected hardship account balances reduces the Company's risks.

Finally, there are other qualitative factors that the Department will consider in determining a company's allowed ROE. It is both the Department's long-standing precedent[270]

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270 For example, the Department has set a utility's ROE at the low end of a range of reasonableness upon a showing that a utility's management performance was deficient. D.P.U. 12-86, at 257-258 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-43, at 218-222 (company's improper handling of a billing error, failure to provide acceptable unaccounted for water report, improper flushing practices, and insufficient communication with customers warranted ROE at lower end of reasonable range); D.P.U. 11-01/D.P.U. 11-02, at 424-426 (company shortcomings in storm response warranted ROE at lower end of reasonable range); D.P.U. 10-114, at 339-340 (company activities related to Department-ordered audit warranted ROE at lower end of reasonable range); D.P.U. 08-35, at 220 (customer service deficiencies warranted ROE at lower end of reasonable range); D.P.U. 08-27, at 136, 137 (failure to conduct competitive bidding for outside consultants and provide detailed rate case expense invoices warranted ROE at lower end of reasonable range); see also D.P.U. 85-266-A/271-A at 172 (failure to fulfill public service obligations warranted ROE at lower end of reasonable range).

and accepted regulatory practice[271] to consider qualitative factors such as management performance and customer service in setting a fair and reasonable ROE. With respect to a company's performance, the Department has determined that where a company's actions have had the potential to affect ratepayers or have actually done so, the Department may take such actions into consideration in setting the ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271 A at 6-14. Thus, the Department may set ROEs that are at the higher end or lower end of the reasonable range based on above average or subpar management performance and customer service. See, e.g., D.P.U. 12-86, at 274-276 & n.181 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-01/D.P.U. 11-02, at 424, 427 (company shortcomings in storm response warranted ROE at lower end of reasonable range).

Based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that an allowed ROE of 9.90 percent is within a reasonable range of rates that will preserve the Company's financial integrity, will allow it to attract capital on reasonable terms and for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this

271 See, e.g., In re Citizens Utilities Company, 171 Vt. 447, 453 (2000) (general principle that rates may be adjusted depending on the adequacy of the utility's service and the efficiency of its management); US West Commc'ns, Inc. v. Washington Utils. and Transp. Comm'n, 134 Wash.2d 74, 121 (1998) (a utility commission may consider the quality of service and the inefficiency of management in setting a fair and reasonable rate of return); North Carolina ex rel. Utils. Comm'n v. Gen. Tel. Company of the Southeast, 285 N.C. 671, 681 (1974) (the quality of the service rendered is, necessarily, a factor to be considered in fixing the just and reasonable rate therefore); Gulf Power Company v. Wilson, 597 So.2d 270, 273 (1992) (regulator was authorized to adjust rate of return within reasonable range to adjust for mismanagement); Wisconsin Pub. Serv. Corp. v. Citizens' Util. Bd., Inc., 156 Wis.2d 611, 616 (1990) (prudence is a factor regulator considers in setting utility rates and can affect the allowed ROE).

case.[272] In making these findings, the Department has considered both qualitative and quantitative aspects of the parties' various methods for determining the Company's proposed ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

XIII. RATE STRUCTURE

A. Rate Structure Goals

Rate structure defines the level and pattern of prices charged to each customer class for its use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class and how rates are designed to recover the cost to serve that rate class. The Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 15-80/D.P.U. 15-81, at 294; D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341; D.P.U. 09-39, at 401.

Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest cost means for society as a whole. Thus, efficiency in rate structure means that it is cost based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 13-75, at 330; D.P.U. 12-25, at 445; D.P.U. 10-114, at 342; D.P.U. 09-39, at 401. In practice, meeting the goal of efficiency should involve rate structures that provide strong signals to consumers to decrease energy consumption

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272 In setting this ROE, the Department took into consideration the amount of the storm fund assessment paid by National Grid pursuant to G.L. c. 25, § 18. See Fitchburg Gas and Electric light Company at al. v. Department of Public Utilities, 467 Mass. 768 (2014).

in consideration of price and non-price social, resource, and environmental factors. D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 12-25, at 445.[273]

The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 13-75, at 331; D.P.U. 12-25, at 444-445; D.P.U. 10-114, at 342; D.P.U. 09-39, at 402.

There are two steps in determining rate structure: cost allocation and rate design. Cost allocation assigns a portion of a company's total costs to each rate class through an embedded allocated cost of service study ("COSS"). The allocated cost of service represents the cost of serving each rate class at equalized rates of return given the company's level of total costs. D.P.U. 15-80/D.P.U. 15-81, at 296; D.P.U. 13-75, at 331; D.P.U. 12-25, at 446; D.P.U. 10-114, at 342; D.P.U. 09-39, at 402-403.

There are four steps to develop an allocated COSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing service. The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as

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273 Effective use of energy resources means reducing the total amount of energy consumed without compromising service reliability through the use of more efficient technologies and practices, with clear and timely pricing information, as part of a sustainable energy policy. See An Act Relative to Green Communities, St. 2008, c. 169; An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298.

demand-, energy-, or customer-related. The third step is to identify an allocator that is most appropriate for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based on the cost groupings and allocators chosen and then to sum for each rate class the costs allocated in order to determine the total costs of serving each rate class at equalized rates of return. D.P.U. 15-80/D.P.U. 15-81, at 296; D.P.U. 13-75, at 332; D.P.U. 12-25, at 446-447; D.P.U. 09-39, at 402-403.

The results of the allocated COSS are compared to the revenues collected from each rate class in the test year. If these amounts are reasonably comparable, then the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of the return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test year revenues are significant, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.P.U. 15-80/D.P.U. 15-81, at 297; D.P.U. 13-75, at 332; D.P.U. 12-25, at 446; D.P.U. 09-39, at 403.

As the previous discussion indicates, the Department does not determine rates based solely on the results of an allocated COSS, but also explicitly considers the effect of its rate structure decisions on the amount customers are billed. For instance, the pace at which fully cost-based rates are implemented depends, in part, on the effect of the changes on customers. In addition, considering the goals of efficiency and fairness, the Department has also ordered the establishment of special rate classes for certain low-income customers and considers the effect of such rates and rate changes on low-income customers. D.P.U. 15-80/D.P.U. 15-81, at 297; D.P.U. 13-75, at 332; D.P.U. 12-25, at 447; D.P.U. 09-39, at 403-404. To reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and prevent any class from subsidizing another class unless a clear record exists to support such subsidies — or unless such subsidies are required by statute, e.g., G.L. c. 164, § 1F(4)(i). In addition, G.L. c. 164, § 94I ("§ 94I") requires the Department, in each base distribution rate proceeding, to design rates based on equalized rates of return by customer class as long as the resulting impact for any one customer class is not more than ten percent.[274] The Department reaffirms its rate structure goals that are designed to result in rates that are fair and cost-based and enable customers to adjust to changes. D.P.U. 15-80/D.P.U. 15-81, at 298; D.P.U. 13-75, at 333; D.P.U. 12-25, at 447; D.P.U. 09-39, at 404.

The second step in determining the rate structure is rate design. The level of the revenues to be generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The overarching requirement for rate design is that a given rate class should produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the Department's rate structure goals discussed above.

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274 An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, Section 20, inserted G.L. c. 164, § 94I:

> In each base distribution rate proceeding conducted by the [D]epartment under Section 94, the [D]epartment shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any [one] customer class would be more than [ten] percent, the [D]epartment shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the [D]epartment.

D.P.U. 15-80/D.P.U. 15-81, at 298; D.P.U. 13-75, at 333; D.P.U. 12-25, at 447; D.P.U. 09-39, at 404.

B. Cost Allocation

1. Introduction

National Grid performed an allocated COSS that directly assigns or allocates, based on cost-causation principles, the Company's total cost of service to each rate class (Exh. NG-PP-1, at 9). There are three steps to the Company's allocated COSS.

First, the Company functionalizes costs by its basic function, such as primary distribution, secondary distribution, and customer (Exh. NG-PP-1, at 13-14).[275] The primary distribution function includes costs related to substations, conductors rated 4 kilovolt ("kV") and higher, transmission, and production assets (Exh. NG-PP-1, at 10). The secondary distribution function includes costs related to conductors and other assets that move electricity from the primary system to customers' premises (Exh. NG-PP-1, at 10). The customer function includes costs related to meters, service drops, billing and collection, and any assets and activities that enable the distribution of electricity to the customer (Exh. NG-PP-1, at 10).

Second, the Company classifies each functionalized cost as demand-, energy-, or customer-related according to the system design or operating characteristics that cause them to be incurred (Exh. NG-PP-1, at 9, 15). Demand-related costs are associated with plant that is designed, constructed, and operated to meet system peak demand or non-coincident class peak demand (Exh. NG-PP-1, at 16). Energy-related costs vary with the electricity delivered to customers (Exh. NG-PP-1, at 16). Customer-related costs are incurred to attach a customer to

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275 There are separate functions for primary distribution and secondary distribution because some customers take service at primary voltages (Exh. NG-PP-1, at 14).

the distribution system, to meter and read usage, and to maintain the meter, service drop, and the customer's account (Exh. NG-PP-1, at 15). Customer-related costs are a function of the number of customers the Company serves, are incurred whether or not a particular customer uses any electricity, and typically do not vary with usage or load profile (Exh. NG-PP-1, at 15).

The third step is the allocation of each functionalized and classified cost element to each rate class based on cost-causation principles (Exh. NG-PP-1, at 9, 16).[276] Costs are either directly assigned or allocated to rate classes (Exh. NG-PP-1, at 16).

In allocating costs to rate classes, the Company used external and internal allocators (Exh. NG-PP-1, at 12). External allocators are developed in special studies derived from the Company's accounting, operating, and other records (Exh. NG-PP-1, at 12). Examples of external allocators are: (1) the numbers of customers in each rate class; (2) class non-coincident peak demands; and (3) historical bad debt experience for each rate class (Exh. NG-PP-1, at 13). Internal allocators are developed within the allocated COSS using a combination of external allocators and other internal allocators (Exh. NG-PP-1, at 13). The Company explains that the internal allocator for property insurance costs is based on plant investment, and therefore, plant investment must be allocated to each rate class before property insurance costs can be assigned to each rate class (Exh. NG-PP-1, at 13).

National Grid set its initial revenue requirement target for each rate class to generate equalized rates of return (Exh. NG-PP-1, at 19). This step resulted in an overall average percentage increase to existing base rates of 5.11 percent (Exh. NG-PP-1, at 21). National Grid

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276 Inherent in this third step, as discussed in the Rate Structure section, is the process of identifying an allocator that is most appropriate for costs in each classification within each function.

proposed to limit the rate increases for Rate R-4 and the street lighting rate classes to ten percent of total revenue (Exh. NG-PP-1, at 21). The Company proposed to allocate the revenue shortfall to all other rate classes based on each rate class's share of base distribution revenue (Exh. NG-PP-1, at 21).

2. Positions of the Parties

a. Attorney General

According to the Attorney General, the Company's "unit cost analysis"[277] does not accurately reflect how costs are allocated in the allocated COSS (Exh. AG-SJR-1, at 8, citing Exh. DPU-33-8, at 35). The Attorney General maintains that in the allocated COSS, the Company allocates costs for production plant, power supply expenses, demonstration and selling expense, miscellaneous expenses, and depreciation expense related to production plant using a rate class's energy consumption (Exh. AG-SJR-1, at 9 citing Exh. DPU-33-8, at 14, 16, 18, 22, 24, 25). However, the Attorney General argues that energy consumption does not appear in the Company's unit cost analysis (Exh. AG-SJR-1, at 8). The Attorney General points out that the Company incorrectly states: "the Company has classified all assets and costs as either [d]emand or [c]ustomer. The Company did not classify any asset or cost as [e]nergy" (Exh. AG-SJR-1, at 8, citing Exh. DPU-1-14).[278]

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277 The unitized cost is the cost associated with a utility function divided by the number of units of service for that function (Exh. AG-SJR-1, at 7). It also is referred to as an embedded cost analysis.

278 According to the Attorney General's analysis, the unitized demand-related cost for the residential rate class decreases from $12.90 per kW per month to $12.72 per kW per month, the customer-related costs decreases from $9.42 per month to $9.31 per month, and the unitized energy-related cost is 0.006 cents per kWh (Exh. AG-SJR-1, at 9).

Further, the Attorney General argues that the Company relies on unitized costs to estimate the cost to serve a customer (Exh. AG-SJR-1, at 9). However, the Attorney General contends that the unitized cost for the rate class will likely be different from the actual cost to serve any particular residential customer (Exh. AG-SJR-1, at 9). Therefore, the Attorney General asserts that the average cost to serve a typical customer is fair to all customers, at a given point in time, "because each customer has a fairly equal chance of being served by facilities that are more expensive or less expensive than average" (Exh. AG-SJR-1, 10).[279]

b. Acadia Center

Acadia Center argues that the economic analysis used in an allocated COSS has evolved since the electric industry was created in the United States (Acadia Center Brief at 11). According to Acacia Center, an allocated COSS misses a significant part of the overall picture for system costs (Acadia Center Brief at 11). Specifically, Acadia Center maintains that the traditional allocated COSS is no longer sufficient in rate design because the shift to cost-effective distributed energy resources is not included in the analysis (Acadia Center Brief at 11). Acadia Center contends that the impact on rates from the incorporation of distributed energy resources into a distribution system is a cutting edge topic and is worthy of consideration by the Department, as well as discussion among stakeholders (Acadia Center Brief at 11). Thus,

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279 In the Attorney General's example, she explains that if a pole is replaced on a customer's street, the customer is likely paying, in sequence: (1) less than the actual cost of service for a few initial years; (2) equal to the cost of service; and (3) less than the actual cost of service towards the end of the useful life of the pole (Exh. AG-SJR-1, at 10).

Acadia Center asserts that the value of distributed energy resources should be a part of the next evolutionary phase in the economic analysis for ratemaking (Acadia Center Brief at 11).[280]

c. Direct Energy

Direct Energy supports reform to the allocated COSS (Direct Energy Brief at 15). In particular, Direct Energy argues that the Department should require the Company to provide a new allocated COSS that allocates costs to both distribution service and basic service (Direct Energy Brief at 15).[281] Direct Energy recommends that the new allocated COSS be reflected in rates at or close in time to the point at which the Company's proposed rate increases are allowed to take effect (Direct Energy Brief at 15). Further, Direct Energy suggests that the Company should participate in a stakeholder process to review the new allocated COSS, and collectively present an agreed upon allocated COSS to the Department for approval (Direct Energy Brief at 15). Finally, Direct Energy argues that the Company should explain its experiences in allocated COSS reform in a statewide investigation on this issue (Direct Energy Brief at 15).

d. Company

According to the Company, its rate proposals are based on its allocated COSS (Company Brief at 198). National Grid asserts that its allocated COSS directly assigns or allocates each element of its revenue requirement among the rate classes in order to determine the costs of providing service to each rate class (Company Brief at 198, citing Exh. NG-PP-1, at 9). The Company notes that results from its allocated COSS at present rates show that the Company is

280 Acadia Center contends that the benefits include capacity savings, transmission savings, reduced energy prices, and the avoided cost of compliance with greenhouse gas emission requirements (Acadia Center Brief at 11).

281 Direct Energy also raises specific issues related to the Company's recovery of basic service costs in Section XI above.

earning an overall return of 1.18 percent, with class returns varying from negative 7.86 percent to 9.86 percent (Company Brief at 200, citing Exh. NG-PP-2(a)).

3. Analysis and Findings

Pursuant to § 94I, the Department in each base distribution rate proceeding is required to design rates based on equalized rates of return by customer class as long as the resulting impact for any one customer class is not more than ten percent. The Department finds that National Grid's proposal to cap the rate increase for Rate R-4 and the street lighting rate classes at ten percent of total revenue complies with § 94I (Exhs. NG-PP-4, at 2; NG-PP-1, at 21; DPU-33-8, Att. at 38 (PDF)).

The Company proposed to allocate the revenue increase above the ten percent cap using the uncapped rate classes' share of test year base distribution revenues (i.e., distribution revenues at present rates) (Exhs. NG-PP-1, at 21; NG-PP-4, at 2; DPU-33-8, Att. at 38 (PDF)). The Department's long-standing policy regarding the allocation of class revenue requirements that exceed a cap is that they should be allocated to those rate classes that do not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return. D.T.E. 03-40, at 384; D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-210, at 214. Moreover, the Department recently directed Fitchburg Gas and Electric Light Company to allocate the revenue requirement in excess of the ten-percent rate cap to those rate classes that did not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return instead of test year distribution revenues. D.P.U. 15-80/D.P.U. 15-81, at 302. For these reasons, and to advance the rate goals of fairness and efficiency, the Department directs the Company to allocate the revenue requirement that exceeds the ten-percent rate cap to those rate classes that did not exceed the cap on the basis of their distribution revenue requirements at equalized rates of return.

The Department notes that allocating the revenue requirement that exceeds the ten-percent rate cap based on revenue requirements at equalized rates of return still results in a significant rate increase for Rate R-4 that violates our continuity goal. Consequently, the Department directs the Company to limit the distribution rate increase for Rate R-4 to 200 percent of the overall distribution rate increase, and to allocate the remaining revenue requirement to the uncapped rate classes based on the ratio of their class revenue requirement at equalized rates of return to the sum of the class revenue requirement at equalized rates of return for all uncapped rate classes.[282]

The Department declines to adopt the Attorney General's recommended modifications to the allocated COSS. The Company functionalized all of its costs as primary distribution, secondary distribution, or customer (Exh. NG-PP-1, at 13). Costs are then classified based on system design or operating characteristics (Exh. NG-PP-1, at 15). When classifying the functionalized costs, costs classified as energy-related vary with the electricity sold to or delivered to customers (Exh. NG-PP-1, at 16). All of the assets and costs in the Company's primary and secondary distribution functions are classified as demand-related, and all of the assets and costs in the Company's customer function are classified as customer-related (Exh. NG-PP-1, at 16). Thus, none of the Company's functionalized costs were classified as

282 The Department makes this directive based on the allocated COSS and revenue requirement in the Company's response to information request DPU-33-8 (Exh. DPU-33-8, Att. at 22). The Department, therefore, directs the Company to apply the 200-percent cap using the allocated COSS and revenue requirements that result from our findings in this Order.

energy-related. In the class allocation step, functionalized and classified costs are then allocated among the rate classes based on causal relationships (Exh. NG-PP-1, at 16). For example, production plant and production O&M were allocated among the rate classes based on each class's test year megawatt-hour deliveries because of the causal relationship (Exh. NG-PP-1, at 16). If customers use more energy, then production plant and O&M costs will increase. Additionally, the Department notes that the Company did not change this classification and allocation method from its allocated COSS that was approved in its last rate case (Exh. DPU-1-7, Att. at 2).

Further, Acadia Center and Direct Energy allege deficiencies in the Company's allocated COSS (Acadia Center Brief at 11; Direct Energy Brief at 15). Having reviewed their arguments, we are not persuaded that the Company's allocated COSS requires any further modification. Therefore, the Department declines to adopt Acadia Center's and Direct Energy's recommendations.[283]

The Department has reviewed National Grid's allocated COSS and, apart from the change to the ten-percent rate cap allocation method and requiring a 200-percent of the overall rate increase cap on the increase to each rate class' distribution revenues, the Department finds that it is reasonable and consistent with Department precedent. D.P.U. 15-80/D.P.U. 15-81, at 303, 309; D.P.U. 13-90, at 240-241; D.P.U. 11-01/D.P.U. 11-02, at 434-437. Accordingly, we accept National Grid's allocated COSS as proposed and with the aforementioned changes. The Department directs the Company to rerun its allocated COSS for submission in its compliance filing to allocate its costs and expenses in excess of the ten-percent cap and 200 percent cap as

283 In Section XI above, we address in further detail Direct Energy's arguments regarding basic service costs allocated to the Company's Basic Service Adjustment Provision.

approved in this Order. In addition, consistent with D.P.U. 15-80/D.P.U. 15-81, at 339-340, the Company shall update the class-based allocators approved in the instant case for the reconciling mechanism tariffs at the time of each tariff's next scheduled rate change.

C. Marginal Cost Study

1. Introduction

The use of a marginal cost study facilitates the development of rates that provide consumers with price signals that accurately represent the costs associated with consumption decisions. D.P.U. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524; D.P.U. 09-30, at 377; D.P.U. 08-35, at 227; D.T.E. 03-40, at 372. Rates based on a marginal cost study allow consumers to make informed decisions regarding their use of utility services, promoting efficient allocation of societal resources. D.P.U. 11-10/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524; D.T.E. 03-40, at 372.

2. Company Proposal

National Grid's marginal cost of service study ("MCOSS") follows the same methodology that was used in its last rate case, with minor updates (Exh. NG-HSG-1, at 3).[284] To develop the MCOSS, National Grid first identified the costs for plant additions that are

284 The Company's MCOSS uses peak electricity use plus energy efficiency reductions as the independent variable in its regression analysis. By contrast, the MCOSS approved in D.P.U. 09-39 did not account for energy efficiency reductions (Exh. NG-HSG-1, at 13). Additionally, two un-essential variables included in the MCOSS approved in D.P.U. 09-39 were omitted from the most recent analysis due to their lack of statistical significance (Exh. NG-HSG-1, at 14). Finally, the Company updated the percentages used to allocate primary from secondary system distribution costs (Exh. NG-HSG-1, at 120).

exclusively demand-related (Exhs. NG-HSG-1, at 7; NG-HSG-2).[285] The Company then adjusted these historical costs to 2014 values using the Handy-Whitman Index (Exhs. NG-HSG-1, at 7; NG-HSG-2). Following this adjustment, National Grid multiplied total demand-related plant addition costs by the percentage of total plant addition costs associated with primary distribution service to separate plant addition costs attributable to primary versus secondary distribution systems (Exhs. NG-HSG-1, at 7; NG-HSG-2). Finally, as the MCOSS is only concerned with plant additions that are made to support load growth, the Company removed from primary and secondary distribution plant costs all plant additions made for replacement (Exhs. NG-HSG-1, at 7; NG-HSG-2; NG-HSG-3; NG-NSG-4; NG-HSG-4A).

By regressing primary distribution plant costs on electricity demand,[286] and a number of other explanatory variables, the Company determined that the marginal plant cost per kilowatt ("kW") of demand for the primary distribution sector was $495.29 (Exhs. NG-HSG-6; NG-HSG-7). Using these results,[287] the Company found that the marginal plant cost per kW of demand for the secondary distribution sector was $160.52 (Exhs. NG-HSG-6; NG-HSG-7). The Company then added general plant costs to the marginal

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285 The following variables were considered to be exclusively demand-related: (1) station equipment; (2) overhead conductors; (3) underground conductors; and (4) line transformers (Exhs. NG-HSG-1, at 7; NG-HSG-2).

286 Electricity demand is defined as system peak electricity use plus energy efficiency savings (Exh. NG-HSG-1, at 10).

287 To discern marginal plant cost in the secondary distribution system, the Company calculated the marginal plant cost for the total distribution system ($655.81), and then subtracted from it the marginal plant cost in the secondary distribution system ($495.29). The Company was not able to establish a relationship between marginal plant costs in the secondary distribution system directly because regression analysis did not lead to significant results (Exh. NG-HSG-1, at 11).

capital cost calculations in each sector and multiplied the resulting figures by the economic carrying charge rate (Exhs NG-HSG-1, at 14-15; NG-HSG-8; NG-HSG-8A).[288] The Company adjusted these amounts for O&M expenses, administrative and general expenses, and working capital (Exhs. NG-HSG-1, at 15; NG-HSG-3; NG-HSG-6; NG-HSG-9; NG-HSG-10). It then adjusted the marginal cost estimates for peak demand, 2016 price-levels, and electricity line losses (Exhs. NG-HSG-1, at 17-18; NG-HSG-10; NG-HSG-11).

National Grid calculated an annual marginal cost of $69.65 per kW of demand for the primary distribution system, and an additional $22.77 per kW of demand for the secondary distribution system (Exhs. NG-HSG-1, at 17; NG-HSG-10). After adjusting for electricity line losses, these marginal cost estimates increase to $71.15 per kW for service taken at the primary voltage level and $97.85 per kW for service taken at the secondary voltage level (Exhs. NG-HSG-1, at 17-18; NG-HSG-11).[289] Finally, the Company calculated the marginal cost for each rate class by multiplying the marginal cost per kW by the demand in the test year for each rate class, and then grossed up these amounts by the uncollectable costs for each rate class (Exhs. NG-HSG-1, at 18; NG-HSG-12).

3. <u>Positions of the Parties</u>

a. <u>Attorney General</u>

The Attorney General raises two concerns with the results of the MCOSS (Exh. AG-SJR-1, at 5-7). First, the Attorney General argues that the model used fails to take into

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288 The economic carrying charge rate is the percentage of capital cost that provides a return on rate base (Exh. NG-HSG-1, at 15).

289 Service taken at the secondary voltage level includes use of both the primary and secondary distribution system.

account important demand-related costs (Exh. AG-SJR-1, at 6). In this regard, she points specifically to the absence of structures (Account 361), poles (Account 364), and underground conduits (Account 366) in the Company's MCOSS calculation (Exhs. AG-SJR-1, at 6; AG-10-6). According to the Attorney General, including these costs would increase marginal cost by approximately 25 percent, which suggests that the current MCOSS results significantly underestimate marginal cost (Exhs. AG-SJR-1, at 6; AG-10-6).

Second, the Attorney General questions the relevance of MCOSS to the ratemaking process, particularly in designing rates (Exh. AG-SJR-1, at 6-7). In particular, she argues that marginal cost pricing does not allow companies to recover embedded costs, which would prevent companies from collecting the full price of providing its service through rates (Exh. AG-SJR-1, at 6-7). According to the Attorney General, the MCOSS is not particularly useful beyond confirming economic theory on the relationship between marginal cost and average cost (Exh. AG-SJR-1, at 6-7).

b. Company

National Grid reiterates the specifics of its MCOSS on brief (Company Brief at 200-201). The Company submits that its MCOSS is based on the same methodology that was approved in D.P.U. 09-39 (Company Brief at 201).

4. Analysis and Findings

The Department has evaluated National Grid's proposed MCOSS and finds that it incorporates sufficient detail to fully understand the methods used to determine the marginal cost estimates. Consistent with the directives in D.T.E. 05-27, at 322 & n.170, the Company excluded from the MCOSS all production, transmission, and customer costs,[290] as they are irrelevant to the design of distribution rates under the Department's current rate design (Exh. NG-HSG-1, at 2). Further, we conclude that the Company followed all computational guidelines set forth by the Department in developing its MCOSS (Exhs. NG-HSG-1, at 9-14; NG-HSG-6; NG-HSG-7; NG-HSG-8).[291]

The Department has evaluated the Attorney General's concern regarding the Company's decision to omit certain variables, but we find that their omission is not inconsistent with Department directives. The Company's analysis is consistent with the MCOSS approved in D.P.U. 09-39. Further, while more recent MCOSS studies approved by the Department have included structures, poles, and underground conduits in their analyses,[292] we find that the nature of these accounts suggests that they might not be necessary for the purpose of the Company's MCOSS. The record shows that the Company omitted Accounts 361, 364 and 366 from the MCOSS because these plant assets have no load-carrying capacity (Exh. AG-10-6). Depending on the circumstances of the load increase, the Company may or may not be correct in this assertion. However, because the directives set forth in D.T.E. 05-27 seek to eliminate the customer component in the MCOSS, the Department finds it appropriate to treat these assets as non-load-carrying because further investment in these assets would not be required to support a

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290 Costs associated with expanding the Company's customer base.

291 These guidelines include: (1) the use of historical data sets no less than 30 years; (2) tests and remedial procedures for issues such as multicollinearity, heteroscedasticity, and autocorrelation; (3) multiple variable regression analysis; (4) consistency check against economic theory concerning marginal cost modeling; and (5) minimal dummy variable and autoregressive term use. See D.T.E. 05-27, at 317-322; D.T.E. 02-24/25, at 243-245.

292 See D.P.U. 13-90, at 241.

marginal increase in load assuming the increase is not the result of an increase in the numbers of customers. Accordingly, based on our review of the Company's MCOSS and the aforementioned considerations, the Department approves the Company's MCOSS.[293]

D. Rate Design

1. Introduction

The Company designed rates to produce a revenue requirement for distribution service of $799.1 million, and proposed to implement its rate design in two phases for Rates R-1, R-2, and G-1 (Exh. NG-PP-1, at 8-9).[294] The Company proposed its rate design with the stated goal of designing fair and equitable distribution rates across all rate classes to reflect the actual cost to serve each customer (Exh. NG-PP-1, at 23).

2. Phase I

In Phase I, the Company proposed several modifications and increases to the charges under its current rate structure (Exh. NG-PP-1, at 8). National Grid proposed a flat rate structure for Rates R-1, R-2, and G-1, and the elimination of its current inclining block rate design implemented in its last base distribution rate case (Exh. NG-PP-1, at 50, 66, 69). Further, the Company proposes to eliminate Rate S-20 (street & area lighting, Company-owned equipment, HPS conversion) and Rate E (limited residential electric space heating) (Exhs. NG-PP-1, at 22;

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293 We acknowledge the Attorney General's position regarding the relevance of the MCOSS in the context of designing rates, and we recognize that rate design is intended to recover embedded costs, which are typically higher than marginal costs. The Department's findings with respect to the Company's rate design proposals are set forth in greater detail below.

294 In Phase II, the Company has not proposed any changes to rate structure for Rates R-4, G-2, G-3, or the street lighting rate classes (Exh. NG-PP-1, at 64).

DPU-23-4). Additionally, National Grid proposes a new light emitting diode ("LED")[295] option on Rate S-1 (Company-owned street lighting rate) (Exhs. NG-PP-1, at 22; NG-PP-23, at 24, 87 (proposed M.D.P.U. Nos. 1270 (MECo) and 528 (Nantucket Electric))). For Rate G-3, the Company proposes to remove the volumetric rate and bill customers only a customer charge and demand charge (Exh. NG-PP-1, at 57-58).

Finally, for both Rates G-2 and G-3, the Company proposes to revise the definition of billing demand to include a demand ratchet (Exh. NG-PP-1, at 22, 54). Currently, a Rate G-2 or G-3 customer's billing demand is based upon the customer's maximum metered use during a 15-minute interval during all hours (Rate G-2) or peak hours (Rate G-3) of the billing month (Exh. NG-PP-1, at 56). A demand ratchet modifies the definition of a Rate G-2 or G-3 customer's billing demand to be the greater of: (1) the maximum metered kW; (2) 90 percent of the maximum metered kilovolt-amperes ("kVA"); or (3) a value based upon 75 percent of the greater of maximum metered kW or 90 percent of kVA during the prior eleven months (Exh. NG-PP-1, at 56).

3. Phase II - Tiered Customer Charges

For residential and small commercial customers and industrial ("C&I") (i.e., Rates R-1, R-2, and G-1), the Company proposes to shift cost recovery from the kWh charge to tiered customer charges in Phase II of its proposal (Exh. NG-PP-1, at 8, 22). The Company's proposed Phase II rate design is to take effect no earlier than six months after the implementation of Phase I rates, or approximately May 1, 2017 (Exhs. NG-PP-1, at 8; DPU-9-16).

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295 LED lights are energy efficient, have long lives, and do not contain hazardous chemicals like the mercury that is contained in mercury-vapor lamps. See D.P.U. 11-01/D.P.U. 11-02, at 471.

National Grid's Phase II rate design proposal implements a four-tiered customer charge (Exh. NG-PP-1, at 32). The Company defines each tier by a kWh range, or a proxy for customer size, intended to represent a customer's monthly maximum demand (Exh. NG-PP-1, at 32, 36, 41). The Company proposes to assign a customer to a tier based on his or her maximum kWh usage in a billing month, over the last twelve billing months (Exh. NG-PP-1, at 36, 41). The customer charge for each succeeding tier is higher relative to the prior tier, and the tiers are intended to approximate a rate design with a customer charge and a demand charge (Exhs. NG-PP-1, at 35-36; NG-PP-Rebuttal-1, at 11). The Company proposes to recover most, if not all, of the customer-related revenue requirement and a portion of the demand-related revenue requirement based upon the billing determinants of the applicably-sized customers in each tier (Exh. NG-PP-1, at 33).

The proposed tiers and customer charges for Rates R-1 and R-2 are listed below.

Phase II

Tier	**kWh**	**Charge per Month**
Tier 1	0 – 250	$6.00
Tier 2	251 – 600	$9.00
Tier 3	601 – 1,200	$15.00
Tier 4	> 1,200	$20.00

(Exh. NG-PP-1, at 65).

According to the Company's billing data, approximately twelve percent of residential customers have a monthly maximum use within the range of the first tier (Exh. NG-PP-1, at 66). Approximately 27 percent of the residential customer bills will fall into the second tier (Exh. NG-PP-1, at 66). The remaining 61 percent of the customers will fall into the third and fourth tiers (Exh. NG-PP-1, at 66). The Company proposes to recover approximately 42 percent of the Rate R-1 and R-2 revenue requirement through the four proposed customer charges, compared to 17 percent of the revenue requirement through the proposed Phase I rate design (Exh. NG-PP-1, at 68).

The proposed tiers and customer charges for Rate G-1 are listed below.

Phase II

Tier	**kWh**	**Charge per Month**
Tier 1	0 – 75	$10.00
Tier 2	75 – 500	$11.00
Tier 3	501 – 2,000	$15.00
Tier 4	> 2,000	$30.00

(Exh. NG-PP-1, at 69).

According to the Company's billing data, approximately 15 percent of G-1 customers have a monthly maximum use within the range of the first tier (Exh. NG-PP-1, at 69). Approximately 29 percent of customer bills will fall into the second tier (Exh. NG-PP-1, at 69). The remaining 56 percent of the customers will fall into the third and fourth tiers (Exh. NG-PP-1, at 69). The Company proposed to recover approximately 31 percent of the Rate G-1 revenue requirement through the four proposed customer charges, compared to 18 percent of the revenue requirement through the proposed Phase I rate design (Exh. NG-PP-1, at 70).

4. Attorney General's Seasonal Rate Design Proposal

The Attorney General proposes an alternative rate design for Rates R-1 and R-2 with a higher volumetric rate during July, August, and September (Exh. AG-SJR-1, at 29). She proposes a $5.50 customer charge, a base distribution rate of $0.04180 per kWh during October through June, and a base distribution rate of $0.04809 during July through September (Exhs. AG-SJR-1, at 29; AG-SJR-11). This rate design was based on the Attorney General's comparison of the summer energy use and the customer's contribution to class non-coincident peak demand, information that was provided by the Company (Exh. AG-SJR-1, at 17). The

Attorney General states that she put forth this proposal as a better proxy for demand related-costs than was instituted in either the Company's Phase I or Phase II rate design proposals (Exh. AG-SJR-1, at 18).

5. Positions of the Parties

a. Attorney General

i. Phase I

The Attorney General argues that the Company's proposed Phase I rate design is not as efficient or fair as it should be (Attorney General Brief at 130). For example, according to the Attorney General's analysis, revenues collected from a customer would only increase by 57 cents for each dollar increase in the cost of serving the customer (Attorney General Brief at 129-130, citing Exh. AG-SJR-1, at 22). Moreover, the Attorney General contends that low-use customers will experience higher bill increases (i.e., a 28.6-percent increase for consumption less than 600 kWh) than high-use customers (i.e., 11.3-percent increase for consumption greater than 600 kWh) (Attorney General Brief at 129, citing Exh. AG-SJR-1, at 12). Therefore, the Attorney General asserts that the Company's Phase I rate design would collect too much revenue from low-use customers and not enough revenues from high-use customers (Attorney General Brief at 129-130).

ii. Phase II – Tiered Customer Charges

The Attorney General argues that the Company's tiered customer charge proposal is "radically" different than any other rate design in effect in Massachusetts or elsewhere in the United States (Attorney General Brief at 131, citing Exh. DPU-12-2; Attorney General Reply Brief at 71-72). According to the Attorney General, the Company's tiered customer charge proposal does a poor job of reflecting the cost of serving different customers and results in unfavorable bill impacts compared to alternative rate designs (Attorney General Brief at 134; Attorney General Reply Brief at 71-72, 76). Moreover, the Attorney General contends that tiered customer charges are inconsistent with the Department's rate design principles and goals (Attorney General Brief at 127). According to the Attorney General, when developing rates, the Department must balance rate design principles, giving the appropriate weight to each principle based on the importance of different policy goals (Attorney General Brief at 128). As discussed in greater detail below, the Attorney General argues that the Company's Phase II rate design proposal: (1) results in arbitrary and incorrect rate changes, violating the rate design goal of fairness; (2) results in large bill impacts, violating the rate design goal of continuity; and (3) fails to recover the appropriate costs from high-use customers, violating the rate design goal of efficiency (Attorney General Brief at 127,132). Therefore, the Attorney General asserts that the Department should reject the Company's tiered customer charge proposal (Attorney General Reply Brief at 76).

(A) Fairness

According to the Attorney General, the Company's tiered customer charge proposal violates the rate design principle of fairness (Attorney General Brief at 133). More specifically, the Attorney General asserts that customers will experience: (1) arbitrary rate changes based on the day of week when the meter is read; and (2) the potential for incorrect rate changes from estimated billing procedures (Attorney General Brief at 132, citing Exh. AG-SJR-1, at 25). As an example, the Attorney General notes that a customer may use more electricity by doing laundry and watching the television at the same time during off-peak, low demand weekend hours, and she contends that it is unfair for a customer to be charged a higher tiered customer charge for a year based on one weekend in one billing cycle (Attorney General Brief at 132, citing Exh. AG-SJR-1, at 25).[296] The Attorney General claims that the Company acknowledged this issue but did not modify its proposal (Attorney General Brief at 132, citing Exh. AG-12-9; AG-12-11). Moreover, the Attorney General assert that the Company did not address the concern that estimated meter reads could place customers into a higher tier customer charge for a year (Attorney General Brief at 133, citing Exh. AG-12-10).

(B) Continuity

The Attorney General argues that the Company's tiered customer charge proposal violates the rate design principle of rate continuity (Attorney General Brief at 132). Based on the Attorney General's analysis of approximately 854,000 customers on Rates R-1 and R-2, she calculated bill impacts ranging from a 14-percent decrease to a 182-percent increase (Attorney General Brief at 133, citing Exhs. AG-SRJ-1, at 27-28; AG-SJR-10; Attorney General Reply Brief at 75, citing Exh. AG-SJR-1, at 27-28). Therefore, the Attorney General contends that the Company's Phase II proposal results in extraordinary and unacceptable impacts on customers'

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296 The Attorney General cites to testimony from her witness to support her argument:

> Some customers use substantially more electricity on the weekends when they (and their children) are home from work or school, doing laundry, watching the television more hours per day, and heating or cooling the home to a more comfortable temperature all day. If a billing period has five Saturdays and Sundays instead of four, such a customer could be placed into a higher tier just because of the quirks of the billing cycle.

(Attorney General Brief at 132, citing Exh. AG-SJR-1, at 25).

bills (Attorney General Brief at 132; Attorney General Reply Brief at 75, citing Exh. AG-SJR-1, at 29).

(C) Efficiency

The Attorney General argues that the Company's tiered customer charge proposal violates the rate design principle of efficiency (Attorney General Brief at 132). According to the Attorney General, the Company's proposal does not better reflect the cost of serving customers because a customer's bill will increase by only 54.1 cents for each dollar increase in costs (Attorney General Brief at 134, citing Exhs. AG-SJR-1, at 23; AG-SJR-8; Attorney General Reply Brief 72, citing Exh. AG-SJR-1, at 23). Moreover, she contends that the tiered customer charges fail to recover the appropriate costs from high-use customers (Attorney General Brief at 132). Therefore, the Attorney General claims that the Company has not supported its claim that tiered customer charges are more reflective of cost-based rates (Attorney General Reply Brief at 72).

Moreover, the Attorney General argues that the Company has not supported its position that the Phase II rate design proposal is a reasonable proxy for a residential rate structure, where the customer charge is designed to recover customer-related costs and a demand charge recovers capacity-related costs (Attorney General Reply Brief at 72, citing Company Brief at 217). In this regard, the Attorney General maintains that there is a weak correlation between a residential customer's annual energy consumption and its contribution to the class's non-coincident peak demand and its contribution to coincident peak demand (Attorney General Brief at 130; Attorney General Reply Brief at 72). As such, she claims that the Phase II rate design is statistically different than a rate design that includes an actual demand charge for residential customers

(Attorney General Brief at 130; Attorney General Reply Brief at 72-73). Further, according to the Attorney General's analysis of more than 12,000 residential customers with demand meters, the Company's Phase II proposal showed the worst results as a proxy demand charge rate compared to rate design alternatives (Attorney General Reply Brief at 72, citing Exh. AG-SJR-1, at 15-17). Therefore, the Attorney General asserts that the Company's tiered customer charge proposal does not meet the rate design principle of efficiency (Attorney General Brief at 129-130).

iii. Seasonal Rate Design

The Attorney General argues that her seasonal rate design proposal is consistent with the Department's rate design goals because it avoids extreme bill impacts, sends appropriate price signal, and is easy for customers to understand (Attorney General Brief at 134-135, 138). According to the Attorney General, a seasonal rate design sets cost-based rates and balances cost causation concerns with customer bill impacts (Attorney General Brief at 134-135; Attorney General Reply Brief at 72).

The Attorney General argues that with a residential customer charge of $5.50 per month and base distribution rates 15 percent higher during the months of July through September, as she recommends, the Company's residential rate design will be closer to the cost of service (Attorney General Brief at 136, citing Exh. AG-SJR-1, at 29). For example, the Attorney General asserts that her proposed seasonal rate design would recover 57.4 cents for each dollar of the cost increase, compared to National Grid's Phase I and Phase II rate design proposals, which would recover 57 cents per dollar increase and 54.1 cents per dollar increase, respectively (Attorney General Brief at 136, citing Exhs. AG-SJR-1, at 30; AG-SJR-12).

Moreover, the Attorney General argues that the 15-percent differential between summer and winter rates is less than the full difference in the cost of serving in these periods, but represents a transitional measure that takes into account customer bill impacts for all customers, including those with largely seasonal consumption (Attorney General Reply Brief at 75, citing Exh. AG-SJR-1, at 29). According to the Attorney General, her proposed seasonal rate design results in bill increases of 10 percent to 38 percent, compared to the Company's tiered customer charge proposal, which she claims results in bill impacts of negative 14 percent to 182 percent (Attorney General Brief at 137, citing Exh. SJR-1, at 30). Thus, the Attorney General asserts that her proposal results in bill impacts that are more reasonable than the Company's (Attorney General Reply Brief at 75, 76).

The Attorney General rejects any notion that there is no cost basis for the 15-percent differential between summer and winter base distribution rates, and she notes that the Company's own cost of service supports her recommendation (Attorney General Reply Brief at 73-74, citing Company Brief at 224). In particular, the Attorney General notes that the Company concluded from its marginal cost of service study that summer coincident peak demand was the major driver of demand-related costs on the Company's system (Attorney General Reply Brief at 74, citing Tr. 8, at 1284-1286). Moreover, the Attorney General contends that even if the Company's system peaks in the winter in a hypothetical year, the system still would be designed to serve summer peaking loads because "one of the critical factors in designing an electric distribution system is the heat associated with peak loads" and the higher ambient temperatures in the summer (Attorney General Reply Brief at 74, citing Exh. AG-SJR-Rebuttal-1, at 16-17). The Attorney General reasons that the carrying capacity of distribution system equipment is higher in the winter than in the summer because of the temperature (Attorney General Reply Brief at 74, citing Exh. AG-SJR-Rebuttal-1, at 16-17). Further, the Attorney General maintains that the Company did not rebut this evidence (Attorney General Reply Brief at 74).

Additionally, the Attorney General argues that system and class peak demands are the primary drivers of demand costs in the allocated COSS (Attorney General Brief at 135). According to the Attorney General's analysis, she claims that there is a stronger correlation between peak-season energy consumption (versus annual energy use) and peak demand because of the significant relationship between a residential customer's energy consumption during the months of July through September and the contribution to system and class peak demands (Attorney General Brief at 135). For example, the Attorney General contends that 48 percent of the variation in customer's contribution to the peak demand is explained by energy consumption during July through September (Attorney General Brief at 135, citing Exhs. AG-SJR-1, at 17; AG-SJR-4). Conversely, she claims that only 27 percent of the variation in peak demand is explained by annual energy use (Attorney General Brief at 135, citing Exhs. AG-SJR-1, at 17; AG-SJR-4). Therefore, the Attorney General asserts that residential customers' consumption during July through September is a better proxy for demand than annual consumption, and, therefore, her proposed seasonal rate design serves as a better proxy for a demand-charge rate because it produces bills that are most similar to demand-based bills (Attorney General Brief at 135, citing Exh. AG-SJR-1, at 19; Attorney General Reply Brief at 73, citing Exh. AG-SJR-Rebuttal-1, at 7-8; Attorney General Reply Brief at 76). Moreover, the Attorney General claims that she and the Company agree that summer peak demands are a critically important factor in determining the cost to serve residential customers (Attorney

General Reply Brief at 74). Thus, she asserts that this fact, and her statistical analyses, prove that the seasonal rate design proposal has merit and the Department should adopt it (Attorney General Reply Brief at 75, 76).

In sum, the Attorney General argues that a seasonal rate design is consistent with the Department's rate design goals because it is fair, promotes rate continuity, is efficient, and is simple (Attorney General Brief at 137-138). The Attorney General recommends that after revenue requirement adjustments, the Department should adopt a $5.50 customer charge for Rates R-1 and R-2, and reduce the volumetric charges by an equal percentage to achieve the seasonal rate design for the residential class's share of the revenue requirement (Attorney General Brief at 138, citing Exh. AG-SJR-1, at 31; Attorney General Reply Brief at 76).

b. DOER

i. Demand Ratchets

DOER argues that the Company's demand ratchet proposal does not provide strong price signals to customers to reduce peak demand, and, therefore, violates the Department's goal of efficiency (DOER Brief at 5, citing D.P.U. 09-39, at 401; DOER Reply Brief at 3, citing D.P.U. 09-39, at 401). DOER contends that under the Company's proposal if a customer reaches a new monthly peak demand in a twelve month period, a demand ratchet increases the customer's demand charge immediately (DOER Brief at 4). DOER claims, however, that a customer would have to maintain a lower level demand for a year before that customer sees a lower demand charge because the charge is only reduced after a customer maintains lower peak monthly demand for eleven consecutive months (DOER Brief at 4-5). DOER argues that the eleven month lag in savings from a lower level demand reduces a customer's incentive to invest in technology that reduces peak demand, making those projects harder to justify because of the longer payback period for capital expenditure (DOER Brief at 5; DOER Reply Brief at 2-3). DOER maintains that it is common industry practice to justify capital investments for commercial customers with short payback periods (DOER Brief at 3). According to DOER, a project is considered more risky if the payback period is longer than one to three years (DOER Brief at 3).

Further, DOER argues that National Grid's analysis purporting to show that a hypothetical customer's energy efficiency savings is minimally impacted by the Company's proposed demand ratchet shows an incomplete picture (DOER Reply Brief at 1-2, citing Company Brief at 227-228; Exh. DPU-15-16). DOER contends that the Company's example uses a customer with a very flat load profile implementing energy efficiency measures (DOER Reply Brief at 1). DOER claims that the Company's example fails to consider the impacts on customers with a load that varies significantly month-to-month (i.e., customers that are more likely to implement peak demand reduction measures) (DOER Reply Brief at 2, citing Exh. DPU-15-16).

In this regard, DOER demonstrates the impact of the demand ratchet on a hypothetical customer with a high peak load implementing a project to reduce peak demand (kW), as opposed to an energy efficiency project reducing kWhs (DOER Reply Brief at 2). According to DOER, a Rate G-3 customer installing a solar plus storage project could reduce its summer peak demand from 400 kW to 250 kW and non-peak demand from 350 kW to 200 kW (DOER Reply Brief at 2). Further, DOER claims that this hypothetical customer expects an immediate reduction to its demand charge based on the new peak demand of 250 kW (DOER Reply Brief at 2). DOER asserts, however, that with a demand ratchet, the customer only sees a reduction to 300 kW (or 75 percent of the existing 400 kW summer peak demand) (DOER Reply Brief at 2). DOER notes that it is not until the investment has been in place for eleven months that the demand charges are assessed at the new demand and the full benefit of the demand reduction project is realized (DOER Reply Brief at 3). Thus, DOER asserts that because of the eleven month lag, a demand ratchet will increase the probability that a customer with a load that varies significantly month-to-month will not invest in demand reduction technologies (DOER Brief at 5; DOER Reply Brief at 2-3).

Finally, DOER argues that the high peak load to total load ratio customers are the exact type of Rate G-2 or Rate G-3 customers that should be incentivized to reduce their peak load, but are the most negatively impacted customers by the proposed demand ratchet (DOER Reply Brief at 3). Thus, DOER recommends that the Department direct the Company in its compliance filing to re-file Rate G-2 and Rate G-3 tariffs without demand ratchets, and to allow DOER an opportunity to evaluate these revised tariffs (DOER Brief at 5; DOER Reply Brief at 3).

ii. Tiered Customer Charges

DOER does not object to the Company's proposed Phase I customer charge proposal, but opposes its Phase II rate design proposal for Rates R-1, R-2, and G-1 (DOER Brief at 6). DOER argues that the Department should reject the tiered customer charge proposal because it: (1) delays the benefits of, and thereby discourages customer investment in, energy savings measures; (2) disproportionately affects lower usage customers; and (3) does not serve as an appropriate proxy for a demand charge (DOER Brief at 7-8). Further, as described in more detail below, DOER contends that the Company did not demonstrate that its Phase II rate design proposal is consistent with the Department's rate structure goals and objectives (DOER Reply Brief at 4). DOER recommends that the Department reject the Company's Phase II proposal and direct the Company in its compliance filing to revise its tariffs to reflect a flat rate structure, and to allow DOER an opportunity to evaluate these revised tariffs (DOER Brief at 6; DOER Reply Brief at 4).

Further, DOER argues that under the Company's Phase II rate design proposal, a customer will pay a higher customer charge based on the previous summer's usage even if the customer installs energy efficiency investments (e.g., efficient heating and cooling) to save money in the upcoming summer (DOER Brief at 7). According to DOER, a delay in savings discourages investment and affects the Commonwealth's goal to reduce energy costs (DOER Brief at 7). Moreover, DOER maintains that the Company did not analyze its Phase II rate design impacts on customer incentives to reduce consumption, including achievement of the Company's three-year energy efficiency plan (DOER Brief at 7, citing DOER 2-18(c); Tr. 5, at 634. Tr. 11, at 1-5, 16-20). Therefore, DOER asserts that the Company's tiered customer charge proposal should not be approved because it risks undermining the Commonwealth's energy policy goal of maximum deployment of energy efficiency (DOER Brief at 7).

(A) Fairness/Continuity

Regarding the rate design goals of fairness and continuity, DOER argues that low-use customers will incur higher bill impacts under the tiered customer charge proposal (e.g., a Rate R-2, low-use customer using 610 kWh per month will experience a 25 percent bill increase while a Rate R-2, high-use customer using 1,000-1,250 kWh per month will experience a 14 to 16 percent bill increase) (DOER Brief at 7-8, citing Exh. LI-JH-1, at 14). DOER expresses concern with these bill impacts because it claims that low-income customers tend to be low-use customers (DOER Brief at 8). Therefore, DOER recommends that the Department reject the Company's tiered customer charge proposal because it disproportionately (and negatively) affects lower and moderate income customers, thereby violating the Department's rate design goal of fairness (DOER Brief at 8).

(B) Efficiency

DOER rejects any notion that a customer's maximum monthly energy use in a year is a proxy for their demand (DOER Brief at 8, citing Tr. 5, at 635). According to DOER, a rate structure based on maximum demand should consist of a customer charge and a per-kW charge based on maximum kW demand (DOER Brief at 8; DOER Reply Brief at 4). Because the Company's tiered customer charges are not based on kW demand or the customer's maximum demand in a month, DOER maintains that the Phase II rate design proposal does not represent a true demand charge (DOER Reply Brief at 4). Further, DOER argues that the Company's tiered customer charge proposal uses a kWh charge as a proxy for demand, and therefore fails to consider a customer's coincident peak demand (DOER Brief at 8; DOER Reply Brief at 4). Accordingly, DOER maintains that the Company's tiered customer charges are not an appropriate and efficient proxy for demand charges (DOER Brief at 8; DOER Reply Brief at 3).

Moreover, because the Company's proposal is based on total kWh usage in a month, DOER argues that a customer does not receive the proper price signal, which a demand charge would provide, to adjust his or her energy consumption within a month (DOER Brief at 8; DOER Reply Brief at 4). For example, DOER contends that under the Company's tiered customer charge proposal, a customer charging an electric vehicle, doing laundry, and using an air conditioner at the same time would be billed the same amount as a customer staggering those activities throughout a month (DOER Brief at 8; DOER Reply Brief at 4). DOER maintains, however, that under a rate design with a true demand charge, the customer's bill would be lower under the staggered activity scenario (DOER Brief at 8; DOER Reply Brief at 4). Thus, for all of these reasons, DOER asserts that the Company's Phase II rate design is contrary to the Commonwealth's energy efficiency goals because it does not provide a price signal to reduce peak demand and lower system wide energy costs (DOER Reply Brief at 4).

c. Low Income Network

i. Phase I

The Low Income Network argue that the Department should reject the customer charge increases proposed by the Company in Phase I for low-income customers taking service on Rate R-2 (Low Income Network Brief at 13).[297] According to the Low Income Network, the Company's proposal to shift revenue collection from the volumetric rates to the customer charges burdens low-use customers that are disproportionately low-income (Low Income Network Brief at 13). The Low Income Network calculates the bill impacts for Rate R-2 customers that range from a 15.9-percent increase in Phase I to up to a 60-percent increase in Phase II (Low Income Network Brief at 14-15, citing Exhs. LI-JH-1, at 14; AG-SJR-1, at 28). Moreover, the Low Income Network argues that the Company's proposed increases to customer charges diverge from the Commonwealth's policies and programs designed to promote energy efficiency and investments in renewable energy and DG (Low Income Network Brief at 13-14).

[297] While the Low Income Network's arguments are focused on low income customers and, therefore, on Rate R-2, many of the low-income customers take service on Rate R-1 (Low Income Network Brief at 13, n.39).

Therefore, the Low Income Network asserts that Rate R-2 customers will not be able to reduce the cost on their bills by reducing consumption under the Company's proposal (Low Income Network Brief at 14).

Further, the Low Income Network argues that a review of rate design proposals should take into account the differences between low income households and higher-income customers (Low Income Network Brief at 14). According to the Low Income Network, low income households generally have lower electric use than higher-income customers (Low Income Network Brief at 14). For example, the Low Income Network asserts that low-income customers on Rate R-2 have median monthly usage of approximately 460 kWh compared to the median usage for Rate R-1 customers of approximately 500 kWh per month (Low Income Network Brief at 14, citing Exhs. LI-JH-1, at 14; LI-2-10, Atts. 1 & 2).

ii. Tiered Customer Charges

The Low Income Network argues that the Department should also reject the Company's tiered customer charge proposal for Rate R-2 customers (Low Income Network Brief at 13). The Low Income Network maintains that the Company's proposed Phase II rate design will not achieve the rate design goals set forth by National Grid of ensuring that DG customers make a "modestly" greater contribution to Company distribution costs (Low Income Network Reply Brief at 3).

Further, the Low Income Network argues that the Phase II rate design proposal runs counter to the Commonwealth's energy efficiency and renewable energy goals (Low Income Network Brief at 15-16, citing Green Communities Act, Acts of 2008, c. 169; Global Warming Solutions Act, Acts of 2008, c. 298; An Act Relative to Solar Energy, Acts of 2016, c. 75; Low

Income Network Reply Brief at 3). The Low Income Network maintains that some of these energy efficiency policies date back to regulatory policies the Department established in the 1980s (Low Income Network Brief at 17, citing Order Opening Investigation, D.P.U. 11-120, at 1-2 (2011)). According to the Low Income Network, increasing customer charges and reducing volumetric charges reduces the incentive to implement energy efficiency measures because the value of each kWh saved is thereby reduced (Low Income Network Brief at 16, citing Exh. LI-JH-1, at 14-15; Low Income Network Reply Brief at 4). Further, the Low Income Network claims that the customer charge tiers create a further barrier to energy efficiency because customers cannot lower their bills for up to twelve months (Low Income Network Brief at 16, citing Tr. 5, at 633-634; Low Income Network Reply Brief at 4). In addition, the Low Income Network maintains that the Company did not perform analysis of the impact of its Phase II rate design proposal on the adoption of energy efficiency measures or renewable energy technology (Low Income Network Brief at 16, citing Tr. 5 at 633-634).

According to the Low Income Network, the Company's tiered customer charge proposal creates barriers for low-income customers that conserve electricity to maintain low electricity costs (Low Income Network Brief at 15). The Low Income Network argues that the Company's tiered customer charge proposal increases the burdens on low income customers who tend to be low-use customers, which the Low Income Network maintains is contrary to the Department's fairness and continuity rate design goals (Low Income Network Reply Brief at 3, 4). Additionally, the Low Income Network contends that by definition, a low-use customer is less likely to contribute to peak demand than a high-use customer (Low Income Network Reply Brief at 4). The Low Income Network maintains that customer charges are assessed equally to all customers without considering monthly use, and therefore, customer charges affect customers with the lower use more than they affect customers with higher use (Low Income Network Reply Brief at 4). Under the Company's proposal, the Low Income Network claims that the median Rate R-2 customer would incur a bill increase of 25 percent and some customers would incur increases of more than 60 percent (Low Income Network Reply Brief at 4-5).

Further, the Low Income Network argues that the Company's tiered customer charge proposal may be confusing to customers (Low Income Network Brief at 16). According to the Low Income Network, customers will not understand their bills or how to control their use if volumetric charges are reduced, customer charges vary annually with use, and customers are unable to monitor their use in real time (Low Income Network Brief at 16, citing Exh. LI-JH-1, at 15; Tr. 8, at 1308; Low Income Network Reply Brief at 4).

Additionally, the Low Income Network maintains that National Grid's proposed Phase II rate design is an inadequate proxy for demand, and, therefore, will not achieve the rate design goals set forth by the Company (Low Income Network Brief at 15, citing Exh. AG-SJR-1, at 16-17; Low Income Network Reply Brief at 3). According to the Low Income Network, the Company fails to prove that distribution costs are driven by maximum monthly energy use as a reflection of demand (Low Income Network Reply Brief at 3). As a result, the Low Income Network asserts that customers can be bumped into a higher tier that does not accurately correlate with the peak demands that drive system costs (Low Income Network Brief at 15). Moreover, the Low Income Network argues that the correlation between historical energy consumption and demand is weak and does not consider whether a customer's maximum historical demand occurred at a time coincident with local or system peaks (Low Income

Network Reply Brief at 3). Instead, the Low Income Network contends that the costs of meeting demand are driven by local and system peaks (Low Income Network Reply Brief at 3, citing DOER Brief at 8; Attorney General Brief at 130, 134; NECEC Brief at 2, 11).

iii. Conclusion

In sum, the Low Income Network argues that Massachusetts law supports minimizing the risk that low-income utility consumers will lose their utility service (Low Income Network Brief at 17, citing G.L. c. 164, § 1F(4)). Further, the Low Income Network contends that the Commonwealth has policies promoting energy efficiency and renewable energy (Low Income Network Brief at 17). In addition, the Low Income Network claims that National Grid's need for rate design reform does not outweigh customers' needs for rate continuity, low-income customers' need for affordability, and policy requirements for energy efficiency and equity, especially in light of the revenue stability provided through revenue decoupling and other risks compensated through the Company's rate of return (Low Income Network Reply Brief at 5). Accordingly, the Low Income Network recommends that the Department reject the Company proposals of raising customer charges and lowering volumetric energy charges because these proposals will undermine the Commonwealth's ability to achieve its energy goals (Low Income Network Brief at 17).

d. Limited Intervenors[298]

i. Demand Ratchet

EFCA argues that the Company did not properly support its demand ratchet proposal for Rates G-2 and G-3 (EFCA Brief at 17, 18-19; EFCA Reply Brief at 15-16).[299] According to

[298] For purposes of this section, the "Limited Intervenors" shall refer to Acadia Center, EFCA, NECEC, and Vote Solar, collectively.

EFCA, the Company did not analyze the basis of the demand ratchet's structure or its impact on current customers to support its proposal (EFCA Brief at 17, 18; EFCA Reply Brief at 16, citing Tr. 7, at 1,108). Moreover, EFCA contends that the only evidence that the Company provided to support its proposal was that a utility in Rhode Island implemented a demand ratchet in 1987 (EFCA Brief at 18; EFCA Reply Brief at 15). However, EFCA claims that the Company did not analyze the similarities and differences between Massachusetts and Rhode Island or the changing conditions over the last 30 years (EFCA Reply Brief at 15-16). EFCA asserts that demand ratchets are an obsolete rate design tool, and National Grid's "back-of-the-envelope" bill impact estimation is inadequate evidence to support the Company's proposed demand ratchet rate design (EFCA Reply Brief at 16, citing Exh. DPU-AC-1-3, Att. 1).

Moreover, EFCA argues that a demand ratchet conflicts with the Department's rate design goals and the concept of efficient price signals for use of resources (EFCA Brief at 6, 11-12; EFCA Reply Brief at 10, citing Exh. EFCA-TM/MW-1, at 8; Boston Gas Co. v. Department of Public Utilities, 405 Mass. 115, 116, (1989)). EFCA contends that, because a demand ratchet reduces the volumetric price signal, it reduces the incentive for customers to manage their use and, as such, may result in higher total energy consumption (EFCA Brief at 5-6, 11-12). Further, EFCA claims that a demand ratchet operates as a fixed charge because it

[299] On September 9, 2016, EFCA filed with the Department a copy of the 2016 NARUC Draft Manual on Distributed Energy Resources Compensation, along with a cover letter and comments regarding the draft manual. In the cover letter, EFCA 'encouraged' the Department to consider certain aspects of the draft manual as we evaluate National Grid's proposed rate increase and design. On September 16, 2016, the Company filed a response to EFCA's filing. EFCA's filing was made well after the record closed, with no opportunity for inquiry. Further, the filing is related to a draft manual that apparently has not yet been adopted by NARUC. The filing constitutes extra-record evidence, to which the Department gives no probative weight. Further, we decline to take official notice of the draft manual pursuant to 220 C.M.R. § 1.10(2).

provides little incentive for a customer to reduce demand each month after the annual peak is set (EFCA Brief at 6, 13, 19). According to EFCA, fixed charges violate the Department's "goal of achieving efficiency in customer consumption decisions" (EFCA Brief at 13, citing Exh. EFCA-TW/MW-1, at 38; EFCA Brief at 19). Therefore, EFCA claims that a "fixed" demand charge does not account for the timing of a customer's demand, and its coincidence with the system peek, and also fails to reflect cost causation (EFCA Brief at 21).

Further, EFCA argues that demand ratchets discourage the adoption of new technologies (e.g., storage and DG), and EFCA notes that a customer with these technologies could face a 21 percent bill increase (EFCA Brief at 5-6; EFCA Brief at 20, citing Exh. EFCA-TW/MW-1, at 50). Moreover, EFCA contends that a customer with solar DG will incur a demand charge based on higher winter demand because there are more daylight hours in the summer than there are in the winter (EFCA Brief at 20, citing Exh. EFCA-TW/MW-1, at 50). Thus, EFCA claims that the demand ratchet proposal does not recognize that these customers have low demand in the summer when the distribution system is most stressed (EFCA Brief at 20, citing Exh. EFCA-TW/MW-1, at 50). EFCA also asserts that the demand ratchet proposal disproportionately penalizes customers for brief equipment outages without recognizing that these customers could reduce system costs for all customers (EFCA Brief at 20-21, citing Exh. EFCA-TW/MW-1 at 52).

EFCA also rejects the notion that there will be a "de minimis" impact of the demand ratchet on the first year of an investment, and EFCA argues that the Company's purported analysis showing the same is limited and does not prove that technology investment will not be "deleteriously" impacted (EFCA Reply Brief at 13-15, citing Company Brief at 227-228;

Exh. DPU-15-16). Instead, EFCA claims that its own analysis show a range of bill impacts, such as bill increases of: 2.6 percent (i.e., similar to the Company's analysis), five percent, and 21 percent (EFCA Reply Brief at 15, citing Exh. EFCA-TW/MW-1, at 50).

According to EFCA, the Company has not carried its burden of proof to warrant approval of the demand ratchet (EFCA Reply Brief at 12). Accordingly, EFCA recommends that the Department reject the Company's demand ratchet proposal (EFCA Brief at 6, 13, 21).

ii. Tiered Customer Charges

(A) Introduction

The Limited Intervenors argue that the Department should reject the Company's tiered customer charge proposal (Acadia Center Brief at 1, 10, 12; EFCA Brief at 6; NECEC Brief at 9; NECEC Reply Brief at 1; Vote Solar Brief at 7). According to the Limited Intervenors, the Company's proposed Phase II rate design does not meet one or more of the Department's rate design goals (i.e., fairness, continuity, simplicity or understandability, efficiency or cost causation) (Acadia Center Brief at 2, 12; EFCA Brief at 3, 15; NECEC Brief at 1, 9; NECEC Reply Brief at 1; Vote Solar Brief at 7).

Further, the Limited Intervenors argue that the Company did not provide evidence of a cost shift from DG customers to non-DG customers or further analysis to support its Phase II rate design proposal (Acadia Center Brief at 2, 10; Acadia Center Reply Brief at 3; EFCA Brief at 9, citing Exh. NG-PP-1, at 28; EFCA Reply Brief at 4; Vote Solar Brief at 7, 8, citing Exhs. NG-PP-1, at 28; NG-PP-Rebuttal-1, at 53; Tr. 5, at 616-617; NECEC Brief at 45-46; NECEC Reply Brief at 1-2, 8-9). Specifically, the Limited Intervenors argue that the Company did not properly analyze the costs or benefits attributable to DG customers in its service territory

(Acadia Center Brief at 12; Acadia Center Reply Brief at 3; EFCA Brief at 9-10, citing Exhs. EFCA-TW/MW-1, at 19, 34, 36; EFCA-TW/MW-Rebuttal-1, at 5 n.9; EFCA-1-11; Tr. 7, at 1,067, 1,070-1,071; EFCA Reply Brief at 4-8; NECEC Brief at 46, citing Exh. LI-1-10; Tr. 5, at 602; Vote Solar Brief at 8, citing Exhs. NG-PP-Rebuttal-1, at 22; DPU-29-6, at 2; Tr. 5, at 620; Vote Solar Reply Brief at 4). According to the Limited Intervenors, without quantifying the costs and benefits attributable to DG customers, the Company cannot demonstrate that a cost-shift occurs (Acadia Center Brief at 10-12; EFCA Brief at 10; NECEC Brief at 45-46, citing Exh. EFCA-TM/MW-1, at 21-22; Vote Solar Reply Brief at 3-4). Thus, the Limited Intervenors claim that because the Company has not proven a cost shift with any analysis, its proposed Phase II rate design is not even necessary (Acadia Center Brief at 12; EFCA Brief at 10-11; EFCA Reply Brief at 4; NECEC Reply Brief at 8-10; Vote Solar Brief at 9; Vote Solar Reply Brief at 3-5). Further, EFCA and NECEC argue that National Grid did not analyze the effects of the tiered customer charges on the Company's alleged cost shift (EFCA Brief at 12, citing Exh. EFCA-1-2; NECEC Reply Brief at 8-9).

NECEC and Vote Solar also argue that the Company has not met its burden with analysis to show that its "ideal rate design," which includes actual residential demand charges, is just and reasonable, in the public interest, and desirable (NECEC Brief at 10-11; NECEC Reply Brief at 2; Vote Solar Reply Brief at 2-3, citing Fitchburg Gas Electric Light Company v. Department of Public Utilities, 375 Mass. 571, 582 (1978)). For example, Vote Solar contends that the Company did not provide evidence showing that actual demand charges will change residential and small C&I behavior or that these customers understand demand charges and have the tools to manage peak demand (Vote Solar Reply Brief at 3, citing Exh. VS-NP-1, at 39-40). Further, NECEC claims that the Company's Phase II rate design does not meet its intent of moving toward demand charges, and Vote Solar argues that no other state-regulated utility in the country requires mandatory demand charges for residential customers (NECEC Brief at 9; Vote Solar Brief at 1). Finally, NECEC and Vote Solar assert that no other utility has implemented a rate design similar to the Company's proposal (NECEC Brief at 45, citing Exh. NECEC-RTB-1, at 14, 35; Tr. 5, at 654-657; Vote Solar Reply Brief at 1, citing Exh. DPU-12-2, Tr. 5, at 638-641).

(B) G.L. c. 164 § 141[300]

EFCA, NECEC, and Vote Solar claim that the Company's proposed Phase II rate design runs counter to state policy to promote energy efficiency and DG and may result in higher electricity prices for all electric customers in the Commonwealth (EFCA Brief at 2, 4; NECEC Reply Brief at 12-13; Vote Solar Brief at 1, 22). In particular, Vote Solar notes that the relevant portion of G.L. c. 164 § 141 ("§ 141) provides: "[i]n all decisions or actions regarding rate designs, the department shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation" (Vote Solar Brief at 22, citing § 141).

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300 G.L. c. 164, § 141 provides:

> In all decisions or actions regarding rate designs, the department shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation. Where the scale of on-site generation would have an impact on affordability for low-income customers, a fully compensating adjustment shall be made to the low-income rate discount.

In Section XIII.E below, we address § 141 as it relates to the impact of on-site generation on affordability of electric service for low income customers, as provided by the second clause of § 141.

According to Vote Solar, the Company did not provide evidence regarding the impact of its tiered customer charges on energy efficiency, compliance with the three-year energy efficiency plan, and incentives to lower demand (Vote Solar Brief at 22-23, citing Exh. DOER-2-18; Tr. 5, at 634; Vote Solar Reply Brief at 11-12). Vote Solar argues that customers are incentivized to implement energy efficiency by the opportunity to save money through lowering their total kWh charges (Vote Solar Brief at 22, citing Exh. DOER-2-16; Tr. 5, at 632; Acadia Center Reply Brief at 7). However, Vote Solar maintains that the purpose of National Grid's tiered customer charges are "to ensure that customers who reduce kWh consumption either through implementation of DG or energy efficiency will pay their fair share of the Company's distribution system," shifting cost recovery away from the kWh charges and causing kWh rates to decline (Vote Solar Brief at 22, citing Exh. NG-PP-1, at 32, 64; Tr. 5, at 750). Vote Solar maintains that the Company does not dispute this evidence (Vote Solar Reply Brief at 11).

Acadia Center challenges the Company's analysis that purportedly shows that tiered customer charges have no effect on energy efficiency, and argues that such analysis is "cherry-picked" and misleading (Acadia Center Reply Brief at 7, citing Exh. LI-1-14, Att.). In particular, Acadia Center contends that the Company's analysis shows a Tier 3 customer using 650 kWh per month reducing consumption by 23 percent after installing energy efficiency technology, causing the customer to drop to Tier 2 with a new baseline of 500 kWh (Acadia Center Reply Brief at 7, citing Exh. LI-1-14, Att.). However, Acadia Center claims that under the same scenario, with a Tier 3 customer using 800 kWh per month, the customer would not drop to Tier 2 after the 23-percent reduction in consumption (Acacia Center Reply Brief at 7, n.27, citing Exh. LI-1-14, Att.).

Further, Vote Solar argues that it is not advocating for "an absolute ban on any rate design that would affect existing incentives for customers to pursue DG and energy efficiency" (Vote Solar Reply Brief at 12, citing Company Brief at 222). Instead, Vote Solar maintains that the Company did not provide the evidence to satisfy its statutory obligation in the instant proceeding (Vote Solar Brief at 22-23, citing § 141; Vote Solar Reply Brief at 12-13).

Moreover, NECEC and Vote Solar argue that § 141 does not require the Department to consider the impacts of the Company's proposed rate design along with the incentives that are provided to energy efficiency and on-site generation (Vote Solar Reply Brief at 12-13, citing Company Brief at 222 (emphasis in original); NECEC Reply Brief at 12-13, citing Company Brief at 222). Rather, NECEC asserts that the Department must be mindful of the effects of rate design on the development of energy efficiency and on-site generation (NECEC Reply Brief at 13).

(C) Continuity and Fairness

Some of the Limited Intervenors argue that the Company's tiered customer charge proposal does not meet the Department's continuity goal and does not improve customer equity (Acadia Center Brief at 2, 12-13; Acadia Center Reply Brief at 5; EFCA Brief at 3; EFCA Reply Brief at 12; NECEC Brief at 27; NECEC Reply Brief at 11). In particular, NECEC contends that the Phase II rate design proposal is based on arbitrary factors that drive significant changes in customers' distribution bills (NECEC Brief at 9). Further, EFCA and NECEC calculate that under the Company's proposal the residential customer charge will increase by up to 400 percent and the small commercial customer charge will increase by up to 200 percent (EFCA Brief at 16; NECEC Brief *at* 27, citing Exh. EFCA-TM/MW-1, at 7, 40). In addition, according to Acadia Center and NECEC, residential annual distribution bill impacts will range from approximate decreases of 10 percent to increases of over 100 percent (Acadia Center Brief at 13, citing Exh. AG-SJR-1, at 26-28; NECEC Brief at 28, citing Exhs. AG-SJR-1, at 24, 27-28; AG-SJR-10). More specifically, NECEC notes that ten percent of R-1 customers will incur bill increases of 45 percent or more, and 1,000 R-2 customers will incur bill increases of 60 percent or more (NECEC Brief at 28, citing Exhs. AG-SJR-1, at 27-28; AG-SJR-10; NECEC Reply Brief at 11-12). Further, NECEC claims that customers will be subjected to two significant changes in rate structure within a short period of time; first, the Company's Phase II proposal, then time-varying rates pursuant to the Department's decision in Time Varying Rates, D.P.U. 14-04-C (2014) (NECEC Brief at 28, citing Exh. NECEC-RTB-1, at 42). NECEC asserts that these two consecutive rate changes violate the Department's rate design goal of continuity (NECEC Brief at 28, citing Exh. NECEC-RTB-1, at 42).

Acadia Center argues that the proposed Phase II rate design is not fair because it shifts cost burden from high-use customers to low-use customers, and low-use customers are disproportionately low-income customers (Acadia Center Brief at 12-13, citing Exh. DPU-AC-1-2, Att.; Acadia Center Reply Brief at 5). For example, Acadia Center calculated only a $5 bill increase for a customer using 2,000 kWh per month, but a $10 monthly bill increase for a customer using 600 kWh per month (Acadia Center Brief at 13, citing Exhs. AC-1-8, Att.; NG-AC-1-1, Att. 1 at 1). Further, Acadia Center contends that approximately 25 percent of customers with usage above the highest tiered customer charge cutoff would pay a per-kWh rate that is lower than their current tail block per-kWh rate (Acadia Center Brief at 13; Acadia Center Reply Brief at 5-6).

Further, Vote Solar maintains that the Company's Phase II rate design proposal is a punitive, one-sided ratchet, proposed without any supporting analysis to determine how likely customers are to move to different tiers (Vote Solar Brief at 18-19, citing Tr. 5, at 631). According to Vote Solar, using twelve months of historical use information to identify maximum monthly use is unreliable because the Company did not study whether the maximum monthly use for a customer is consistent year to year (Vote Solar Brief at 17, citing Exh. NG-PP-Rebuttal-1, at 29; Tr. 5, at 728-729; RR-NECEC-1, Att.; Vote Solar Reply Brief at 8-9). Moreover, NECEC contends that similar customers could have nearly identical patterns of use (e.g., customer one uses 600 kWh in a billing period while customer two uses 599 kWh), but a customer on Tier 3 for distribution services is billed 33 percent more than a customer on Tier 2 (NECEC Brief at 22, citing Exh. EFCA-TW/MW-1, at 33; NECEC Reply Brief at 12). Therefore, NECEC argues that this divergence of bills is unfair and does not reflect cost of service differences (NECEC Brief at 22-23).

(D) Simplicity

The Limited Intervenors argue that the Company's tiered customer charge proposal does not meet the Department's simplicity goal (Acadia Center Brief at 2, 14; EFCA Brief at 3; EFCA Reply Brief at 12; NECEC Brief at 23, citing D.T.E./D.P.U. 06-82-A, at 75; NECEC Reply Brief at 10; Vote Solar Brief at 15-16; Vote Solar Reply Brief at 8-9). Further, Acadia Center contends that the Company's Phase II rate design proposal is a departure from traditional rate design and should have included bill management tools because potential bill impacts are large (Acadia Center Reply Brief at 6).

The Limited Intervenors also argue that customers cannot easily monitor, respond to, and manage bills under the Company's proposed Phase II rate design, and NECEC alleges that customers would find the adjustment to a tiered customer charge difficult (Acadia Center Brief at 14; Acadia Center Reply Brief at 6; EFCA Brief at 15, citing Exh. LI-2-12; NECEC Brief at 23-25, 27, citing Exhs. EFCA-TW/MW-1, at 41; NECEC-RTB-Rebuttal-1, at 16; Vote Solar Reply Brief at 8). Further, NECEC and Vote Solar contend that customers will not know when they are close to a tier boundary because they are unable to monitor use in real time (NECEC Brief at 25, citing Exh. LI-2-12; Tr. 5, at 626-627; Vote Solar Brief at 16; Vote Solar Reply Brief at 8). Additionally, Acadia Center and NECEC claim that customers will not understand what kinds of behavior will move them to a higher tier or whether energy efficiency and conservation measures will drop them into a lower tier (Acadia Center Brief at 14; NECEC Brief at 24-25). Accordingly, NECEC asserts that an arbitrary event could set a customer's new maximum annual kWh and move the customer into a higher tier (NECEC Brief at 25).

NECEC also argues that the Company's proposed Phase II rate design is complex and leaves other arbitrary consequences in place, such as the length of a billing period, number of weekend days within a billing period, and estimated meter reads, that could affect a customer's maximum monthly use and customer charge tier for an entire year (NECEC Brief at 22, citing Exhs. AG-SJR-1, at 24-26; NG-PP-Rebuttal-1, at 63; AG-SJR-Rebuttal-1, at 16; NECEC Reply Brief at 12). Further, Vote Solar contends that a customer may take action to lower his or her maximum monthly use, but it may not result in a bill reduction (Vote Solar Brief at 17-18, citing Tr. 5, at 629; Vote Solar Reply Brief at 9). NECEC and Vote Solar maintain that it is unfair to subject customers to a higher tiered customer charge for twelve months based on one month's use, but to be moved to a lower tier, the customer must wait until he or she sustains a reduction in maximum use for twelve months (NECEC Brief at 22; Vote Solar Brief at 18-19, citing Tr. 5, at 630-631; Vote Solar Reply Brief at 8). EFCA describes the tiered customer charge proposal as having the same effect as the demand ratchet proposal for Rates G-2 and G-3 (EFCA Reply Brief at 9-10, citing Exh. EFCA-TW/MW-1, at 11).

Vote Solar also rejects the notion that customers are able to respond to demand charges, and, therefore, the Company's tiered customer charge proposal is acceptable, as Vote Solar argues that the Company's position is based on its experiences with larger commercial customers, not residential customers (Vote Solar Brief at 15-16, citing Tr. 5, at 675-676). Further, NECEC contends that residential and small commercial customers will not understand demand, much less the relationship between demand and their monthly use (NECEC Brief at 24, citing Exhs. VS-NP-Rebuttal-1, at 18; EFCA-TM/MW-1, at 41).

Moreover, NECEC and Vote Solar argue that there is no evidence in National Grid's Smart Energy Solutions Program, which studied customer behavior under time-of-use/critical peak pricing and peak-time rebate programs, that supports the Company's position that customers would understand the tiered customer charge proposal (Vote Solar Brief at 16, citing Tr. 5, at 624-626; NECEC Brief at 23-24, citing Exh. NECEC-RTB-Rebuttal-1, at 15; Tr. 5, at 625; NECEC Reply Brief at 10, citing Tr. 5, at 625-626). Further, although the Company plans to implement an outreach and education program for its tiered customer charges, NECEC and Vote Solar contend that the Company did not develop the materials and present this evidence (NECEC Reply Brief at 11; Vote Solar Brief at 17, citing Exh. VS-2-6; Vote Solar Reply Brief at 9).

Finally, in response to the Company's argument that time-varying rates are complicated, Acadia Center and NECEC maintain that customers are able to respond to time-varying prices for other products, such as travel and cell phones (Acadia Center Reply Brief at 6; NECEC Reply Brief at 10). Acadia Center asserts that as technology advances, more complicated rate designs become more feasible (Acadia Center Reply Brief at 5-6).

(E) Efficiency

The Limited Intervenors argue that the Company's tiered customer charge proposal does not meet the Department's rate design goal of efficiency because it does not send transparent price signals, it is not based on cost-causation principles, it is not an improvement from current rate design, and it is unjustified (Acadia Center Brief at 2, 14, citing Exh. AG-SJR-1, at 14-24; EFCA Brief at 3; EFCA Reply Brief at 11; NECEC Brief at 14, 16-17, 23; Vote Solar Brief at 9-10, 12 n.8, 15). Therefore, the Limited Intervenors claim that the Company's tiered customer charge proposal fails to represent an efficient, cost-based rate design (Acadia Center Brief at 14-15; Acadia Center Reply Brief at 7-9; EFCA Reply Brief at 11; NECEC Reply Brief at 2-3; Vote Solar Brief at 15).

Further, EFCA contends that the Company has conflated historical and future costs in designing its tiered customer charges (EFCA Brief at 14). In this regard, EFCA notes that historical costs are fixed, sunk costs, but the purpose of rate design is to not only recover historical costs, but also to send clear price signals in order to encourage the efficient use of the distribution system and reduce avoidable future costs (EFCA Brief at 14). EFCA contends that the volumetric rate sends a price signal to customers that reduced system use results in reduced costs (EFCA Brief at 14). Further, EFCA maintains that this price signal will reduce the need for supply-side resources, and, therefore, reduce long-run electricity costs for all customers (EFCA Brief at 15). Thus, EFCA and Vote Solar assert that the tiered customer charge proposal does not "provide strong signals to customers to decrease excess energy consumption in consideration of price and non-price social, resource, and environmental factors" because customers will be locked into a tier for a year (EFCA Brief at 4, 15; Vote Solar Reply Brief at 8-9). Accordingly, EFCA and Vote Solar maintain that such results are contrary to the Department's goal of achieving efficient price signals and efficiency in customer consumption decisions (EFCA Brief at 15; Vote Solar Reply Brief at 8-9).

Moreover, the Limited Intervenors disagree with the Company's portrayal of the relationship between a customer's maximum monthly kWh use and maximum hourly kW demand (Acadia Center Brief at 14-15; EFCA Brief at 15; NECEC Brief at 17; NECEC Reply Brief at 3-4; Vote Solar Brief at 9-10). According to NECEC and Vote Solar, the low R-squared[301] values produced from the Company's analysis demonstrate a weak relationship between maximum billed use and maximum hourly load for each customer charge tier, and therefore, maximum annual kWh serves as poor proxy for a customer's contribution to non-coincident peak demand (NECEC Brief at 16-18, citing Exh. VS-NP-1, at 26; Vote Solar Brief at 10-12, citing Exh. AG-SJR-5; DPU-9-8; Tr. 5 at 637-638, 688-689; Vote Solar Reply Brief at 6, citing Exh. DPU-9-8, Att.). Further, EFCA, NECEC, and Vote Solar argue that a

[301] The R-squared analysis measures the strength of a relationship (Exh. DPU-15-9; Tr. 8, at 1218). A R-squared value of one means that the model explains all the variability of the data, and a R-squared value of zero means that the model explains none of the variability of the data (Tr. 5, at 636).

customer's highest month of use is a worse indicator of the customer's maximum demand than a customer's average energy use (i.e., current rates) (EFCA Brief at 15; EFCA Reply Brief at 11, citing Exh. EFCA-TW/MW-1, at 25-28; NECEC Brief at 17-18, citing Exhs. NECEC-RTB-1, at 19-20; DPU-NECEC-1-4, Att.; EFCA-TW/MW-1, at 27-29; RR-DPU-27, Att.; NECEC Reply Brief at 5; Vote Solar Brief at 12, n.8, citing Exh. NECEC-RTB-1, at 19-20; RR-DPU-27, Att.; DPU-9-8, Att.).[302]

According to the Limited Intervenors, a tiered customer charge based on a customer's maximum monthly kWh use as a proxy for non-coincident peak demand is an inferior metric because it does not link rate design to the distribution system peak loads that drive distribution system costs (Acadia Center Brief at 15, citing Exh. AC-AA-Rebuttal-1, at 1-2; Acadia Center Reply Brief at 8-9; EFCA Brief at 16; NECEC Brief at 11; NECEC Reply Brief at 4; Vote Solar at 9-10, 12, 13, citing Fitchburg Gas and Electric Light Company 375 Mass. at 582). Vote Solar and NECEC contend that system costs are incurred based on customer's demand coinciding with collective peak demand of all customers, which Vote Solar claims that the Company acknowledges (NECEC Reply Brief at 4; Vote Solar Brief at 13-14, citing Exhs. NG-PP-1, at 31; VS-NP-1, at 27; EFCA-TW/MW-1 at 26-27; AC-AA-1, at 13; NECEC-RTB-1, at 18). Moreover, EFCA and Vote Solar claim that the Company did not perform an analysis showing that non-coincident peak demand charges actually reflect a customer's contribution to system costs, improve system utilization, cause customers to shift use in a way that reduces use during peak system hours, or reduce system costs (EFCA Brief at 16; NECEC Brief at 16; NECEC

302 EFCA contends that the Company acknowledges its analysis was inadequate, and Vote Solar maintains that the Company admitted its tiered customer charge proposal was a "second-best solution" (EFCA Reply Brief at 11, citing Tr. 5, at 688; Vote Solar Brief at 2, 10, n.6, citing Exh. NG-PP-1, at 31; Tr. 5, at 637).

Reply Brief at 3-4; Vote Solar at 14, citing Tr. 5, at 677-679). NECEC maintains that distribution system costs are highly dependent on the time of day and the time of year that services are used, and distribution system costs result from the infrastructure needed to provide service during times of the highest customer use (NECEC Brief at 11-12, citing Exhs. NECEC-RTB-1, at 18; VS-NP-Rebuttal-1, at 7; Tr. 5, at 666-667, 774; Vote Solar Brief at 13, citing Exhs. NG-PP-1, at 31; AC-AA-1, at 13; NECEC-RTB-1, at 18). Moreover, Vote Solar asserts that the Company admitted that reductions in customer use during peak hours benefit the system and reduces costs (Vote Solar Brief at 13, citing Tr. 5, at 681). NECEC maintains that rate design should be based on costs incurred during times when demand is the highest (NECEC Brief at 12, citing Exhs. NECEC-RTB-1, at 18; AC-AA-Rebuttal-1, at 1; EFCA-TW/MW-1, at 26-27; VS-NP-1, at 27; VS-NP-Rebuttal-1 at 7; Tr. 5, at 774). Given these considerations, the Limited Intervenors claim the tiered customer charges, based on an individual customer's non-coincident peak demand, is not an improvement over standard volumetric charges and does not improve cost-causation (Acadia Center Brief at 14-15; Acadia Center Reply Brief at 8, citing Exh. AG-SJR-1, at 14-24; EFCA Brief at 15, citing Exh. EFCA-TW/MW-1, at 25; NECEC Brief at 16-19; NECEC Reply Brief at 5; Vote Solar Brief at 12-15; Vote Solar Reply Brief at 6).

NECEC argues that the Company's proposed Phase I rates and current rates are more reflective of the cost to serve than the Company's proposed Phase II rates (NECEC Brief at 15-16, citing Exhs. AG-SJR-20-30; AG-SJR-6; AG-SJR-7; AG-SJR-8). For example, NECEC claims that under Phase I rates, a $1 increase in cost of service would correspond to a 57 cent increase in revenue recovery, but under Phase II rates, the same $1 increase would correspond to only a 54 cent increase in revenue recovery (NECEC Brief at 16, citing Exhs. AG-SJR-1, at 22-23; AG-SJR-7; AG-SJR-8).

EFCA takes issue with Company's argument that a customer's maximum demand represents a customer's potential to contribute to the capacity requirements of the distribution system (EFCA Reply Brief at 10-11, citing Company Brief at 220-221; Exh. EFCA-TW/MW-1, at 25). According to EFCA, a customer's individual peak demand will not put the greatest strain on the system because individual peaks do not occur at the exact same time for all customers (EFCA Reply Brief at 11, citing Exhs. EFCA-TW/MW-1, at 26; DPU-9-13).

Further, the Limited Intervenors argue that the Company's counter argument that existing distribution demand charges already are based on non-coincident peak demand is flawed (Acadia Center Reply Brief at 8-9; EFCA Reply Brief at 10-11; NECEC Reply Brief at 4; Vote Solar Reply Brief at 7). In particular, Acadia Center contends that the Company does not explain why non-coincident peak demand is the basis of existing demand charges, and argues that metering limitations are a primary reason that existing demand charges are based on the non-coincident peak demand during a billing period (Acadia Center Reply Brief at 9). According to Vote Solar and NECEC, existing demand charges for large C&I customers do not justify application of such charges to small C&I and residential customers because these customers do not use the distribution system in the same way (Vote Solar Reply Brief at 7-8, citing Exh. VS-NP-Rebuttal-1, at 12; NECEC Brief at 12-13, citing Exhs. NECEC-RTB-1, at 27; VS-NP-1, at 27; NECEC Reply Brief at 4-5). Further, Vote Solar maintains that many small customers share one feeder, creating diversity of demand, whereas a medium or large C&I customer can comprise the majority of demand on an individual feeder (Vote Solar Reply Brief at 7-8, citing Exh. VS-NP-Rebuttal-1, at 12; NECEC Brief at 12, n.5, citing NECEC-RTB-1, at 27, 29; VS-NP-1, at 27; VS-CP-Rebuttal-1, at 12-13; NECEC Reply Brief at 5). Moreover, NECEC contends that peak demand drives that the size and costs of the distribution system (NECEC Brief at 12, citing Exh. NG-PP-1, at 30, 33; NG-PP-Rebuttal-1, at 13; AG-SJR-Rebuttal-1, at 15; NG-PP-2; Tr. 10, at 1557-1558, 1574-1575). Thus, EFCA, Vote Solar, and NECEC argue that the Company's proposed Phase II rate design approach ignores diversity of demand, discussed in planning for distribution system investment (EFCA Reply Brief at 11, citing Exhs. EFCA-TW/MW-1, at 26; DPU-9-13; NECEC Brief at 11; NECEC Reply Brief at 4-5; Vote Solar Reply Brief at 7).

Finally, according to NECEC, tiered customer charges are an inaccurate measure of cost causation for customers who have installed solar DG (NECEC Brief at 20). NECEC maintains that solar DG customers typically reduce demand during summer months and are likely to have higher demand during off-peak months on the distribution system (NECEC Brief at 20, citing Exh. NECEC-RTB-1, at 21-24). Accordingly, NECEC asserts that tiered customer charges fail to provide accurate price signals indicating the value that solar DG provides in reduced costs on the distribution system (NECEC Brief at 21).

(F) Conclusion

In sum, the Limited Intervenors argue that the record does not support a finding that the Company's tiered customer charge proposal is just and reasonable (Acadia Center Brief at 2; EFCA Brief at 11; NECEC Reply Brief at 9-10; Vote Solar Brief at 7, citing Attorney General v. Department of Telecommunications and Energy, 438 Mass. 264, n.13 (2002)). Further, Vote Solar claims that no other utility uses a rate design similar to the Company's proposed tiered customer charges (Vote Solar at 3, citing Exh. DPU-2-12; Tr. 5, at 640). Therefore, the Limited Intervenors conclude that National Grid has not met its burden to justify the tiered customer charge proposal, and the Department should reject it (Acadia Center Brief at 1, 10, 12; EFCA Brief at 6; NECEC Brief at 9; NECEC Reply Brief at 3; Vote Solar at 9, citing Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 375 Mass. 582 (1978)).

iii. Seasonal Rate Design

Acadia Center and NECEC support the Attorney General's seasonal rate design proposal (Acadia Center Brief at 2, 17-18; Acadia Center Reply Brief at 11; NECEC Brief at 29-30). According to NECEC, the Department stated that it would consider seasonally differentiated rates where they were shown to more effectively indicate the underlying costs of the distribution system and encourage efficient consumption of electricity (NECEC Brief at 29, citing D.P.U. 10-70, at 330). Acadia Center and NECEC allege that the Attorney General's rate design proposal improves the relationship to cost of service compared to the Company's Phase I and Phase II rate design proposal (Acadia Center Brief at 17, 18; NECEC Brief at 29, citing Exhs. AG-SJR-1, at 22-24, 30; AG-SJR-7; AG-SJR-8; AG-SJR-12).

Acadia Center and NECEC also argue that the Attorney General's seasonal rate design meets the Department's rate making goals (Acadia Center Brief at 18; NECEC Brief at 29-30). They assert that the seasonal rate design is cost-based, results in reasonable bill impacts, is simple and understandable, and improves efficiency and cost causation (Acadia Center Brief at 18; NECEC Brief at 29-30, citing Exhs. AG-SJR-1, at 27-28, 30; NECEC-RTB-Rebuttal-1, at 3, 12; EFCA-TW/MW-Rebuttal-1, at 22-23).

Further, NECEC argues that a higher rate in the summer months would better align time of use with underlying costs (NECEC Brief at 29-30, citing Exhs. AG-SJR-1, at 16-20; AG-SJR-2; AG-SJR-4; AG-SJR-5). In this regard, NECEC contends that bill impacts range from 10 percent to 38 percent (compared to negative 14 percent to 181 percent under the Phase II rate design proposal) (NECEC Brief at 29, citing Exh. SG-SJR-1, at 27-28, 30). According to NECEC, the Rate G-1 seasonal rate design has similar bill impacts to the Company's proposed Phase I rate design (NECEC Brief at 30, n.15, citing RR-DPU-47; Tr. 10, at 1569-1570). Finally, NECEC asserts that seasonal rates are more efficient, do not require advanced meters, and can be implemented in conjunction with time-varying rates (NECEC Brief at 30, citing D.P.U. 14-04-C; Exhs. EFCA-TW/MW-Rebuttal-1, at 22-23; NECEC-RTB-Rebuttal-1, at 12-13).

NECEC also argues that the Company disputed the Attorney General's proposed seasonal rate design with two, unconvincing arguments (NECEC Reply Brief at 13). First, NECEC rejects the Company's argument that system-wide coincident peak demand reduction from a seasonal rate design is not beneficial because some feeders might not realize a reduction in their peak demand, as NECEC notes that the majority of the Company's feeders peak in the summer (NECEC Reply Brief at 14, citing Exhs. NECEC-RTB-Rebuttal-1 at 9-10; NG-PP-Rebuttal-1, at 14-15; NECEC-1-7; Company Brief at 224). Thus, NECEC asserts it cannot be disputed that for nearly all feeders, summer electricity use is the driver of demand-related system costs (NECEC Reply Brief at 14, citing Company Brief at 199, 217).

Second, NECEC rejects the Company's argument that seasonal rates will result in "arbitrarily" higher net metering credits (NECEC Reply Brief at 14, citing Company Brief at 224). According to NECEC, the higher value of net metering credits in the summer months from the Attorney General's proposed seasonal rate design are not "arbitrary" because the value of net metering credits will rise with summer distribution rate (NECEC Reply Brief at 14). Further, NECEC contends that a higher summer rate is appropriate because cost responsibility for the majority of demand-related costs is based on the customer class contribution to summer peak demands in the Company's allocated COSS (NECEC Reply Brief at 14, citing Exhs. AG-SJR-1, at 17, 29-30; AG-SJR-Rebuttal-1, at 15-16). Therefore, NECEC asserts that there is nothing arbitrary about crediting excess generation from net metering facilities at a higher rate when that rate accurately reflects the increased value of the demand reduction associated with that generation during the summer months (NECEC Reply Brief at 14).

e. AIM and TEC

AIM and TEC argue that National Grid did not properly support its demand ratchet proposal for Rates G-2 and G-3 and did not analyze the impacts of the demand ratchet proposal on current customers (AIM and TEC Reply Brief at 8). According to AIM and TEC, the Company's own evidence contradicts its basis for proposing the demand ratchet (AIM and TEC Reply Brief at 8). For example, AIM and TEC contend that Rate G-3 customers' demand patterns show that the Rate G-3 class load is different than demand during the monthly system coincident peak (AIM and TEC Reply Brief at 5, citing Exh. NG-PP-3(b)). AIM and TEC claim that this data contradicts the Company's assertion that a customer's maximum demand during an annual period reflects the customer's contribution to coincident peak demand (AIM and TEC Reply Brief at 5). According to AIM and TEC, National Grid sizes its circuits to accommodate coincident peak demand, not the summation of non-coincident peak demands (AIM and TEC

Reply Brief at 5). Thus, AIM and TEC contend that cost causation occurs when a customer's peak demand coincides with the maximum monthly peak demand (AIM and TEC Reply Brief at 5). Therefore, AIM and TEC claim that because a demand ratchet does not account for the timing of a customer's demand, and its coincidence with system peak, and because it fails to reflect cost causation, the demand ratchet results in a fixed annual charge (AIM and TEC Reply Brief at 7). Accordingly, AIM and TEC assert that the Department should reject the Company's claim that all Rate G-2 and Rate G-3 customers pay for demand through a demand ratchet that is based on their annual peak load, regardless of when it occurs (AIM and TEC Reply Brief at 5).

Further, AIM and TEC argue that the demand ratchet proposal will reduce customer incentives for behavior that is beneficial to the system and demand reduction goals (AIM and TEC Reply Brief at 7). AIM and TEC agree with DOER that the Company's demand ratchet proposal will impede the Commonwealth's goal of achieving demand reduction and mitigating peak load growth because it operates as a fixed charge (AIM and TEC Reply Brief at 7-8).

Moreover, AIM and TEC argue that the demand ratchet is really a "de facto" stand-by charge for customer's with behind the meter DG because these customers will not be able to reduce their demand charge for an entire year (AIM and TEC Reply Brief at 4, 6, 8). In this regard, AIM and TEC contend that the demand ratchet proposal disproportionately penalizes customers for brief equipment outages (e.g., combined heat and power ("CHP")) without recognizing the benefit of demand reductions that could reduce system costs for all customers (AIM and TEC Reply Brief at 6). For example, AIM and TEC claim that a customer with a 30-minute CHP outage during a month that the grid has excess capacity (e.g., April) could result in additional demand charges of over $21,000 for that twelve-month period (AIM and TEC

Reply Brief at 6). Further, AIM and TEC maintain that some customers with DG must interrupt on-site generation when there are power quality issues completely beyond the customer's control (AIM and TEC Reply Brief at 6). Moreover, AIM and TEC note that current DG owners schedule maintenance during off-peak periods to avoid demand charges (AIM and TEC Brief at 7). According to AIM and TEC, a demand ratchet eliminates the incentive to schedule maintenance during off-peak periods because demand charge cost avoidance can no longer justify the added cost of overtime and weekend labor rates for the off-peak work (AIM and TEC Reply Brief at 7). Thus, AIM and TEC assert that the Company's demand ratchet proposal will unfairly penalize these customers and cause negative impacts for customers with distributed resources (AIM and TEC Reply Brief at 6-7).

AIM and TEC also take issue with National Grid's hypothetical customer example, and they argue that it represents a business only operating in the summer and thereby only paying a demand charge during the summer, but requiring a fixed distribution investment from the Company to accommodate this customer's peak load (AIM and TEC Reply Brief at 4-5, citing Exh. NG-PP-1, at 59). AIM and TEC contend that the scenario the Company modeled to support its proposal for a demand ratchet is rare and should not be used to justify a new charge applying to all customers (AIM and TEC Reply Brief at 5).

In light of these considerations, AIM and TEC argue that the Company has not carried its burden of proof to warrant approval of the proposed demand ratchet (AIM and TEC Reply Brief at 8, citing D.T.E. 99-118, at 7, n.5). Additionally, AIM and TEC argue that the Company's rationale for its demand ratchet proposal is confused, illogical, and flawed, and the Company's proposal violates the Department's rate design principles (AIM and TEC Reply Brief at 4, 7-8).

Thus, AIM and TEC recommend that the Department reject the Company's demand ratchet proposal (AIM and TEC Reply Brief at 10).

f. PowerOptions

i. Demand Ratchet

PowerOptions argues that the Company did not properly support its demand ratchet proposal for Rate G-2 and Rate G-3 because it did not provide evidence of the impacts of the demand ratchet proposal on current customers (PowerOptions Reply Brief at 5-7). Further, PowerOptions claims that the Company's demand ratchet proposal is a sweeping change in the manner of billing medium and large C&I customers (PowerOptions Reply Brief at 6).

PowerOptions argues that the Company's demand ratchet operates as a fixed charge (PowerOptions Reply Brief at 7). According to PowerOptions, fixed charges violate the Department's "goal of achieving efficiency in customer consumption decisions" because it provides little incentive to reduce demand each month after the peak has been set (PowerOptions Reply Brief at 7).[303] Therefore, PowerOptions contends that a fixed demand charge does not account for the timing of customer demand and its coincidence with the system peak, and also fails to reflect cost causation (PowerOptions Reply Brief at 7). Thus, PowerOptions claims that the demand ratchet proposal is unfair and causes negative impacts for customers with distributed resources (e.g., solar) (PowerOptions Reply Brief at 7).

Further, according to PowerOptions, the Company's billing demand definitions are confusing for customers (PowerOptions Reply Brief at 6). PowerOptions maintains that

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303 PowerOptions agrees with DOER that the Company's demand ratchet proposal will impede the Commonwealth's goal of achieving demand reduction and mitigating peak load growth (PowerOptions Reply Brief at 7, citing DOER Brief at 5).

calculating a value based upon 75 percent of the greater of maximum metered kW or 90 percent of kVA during the prior eleven months is unclear (PowerOptions Reply Brief at 6). Therefore, PowerOptions argues that customers will be unable to manage their facilities appropriately (PowerOptions Reply Brief at 6). Accordingly, PowerOptions asserts that the Department should reject the Company's demand ratchet proposal (PowerOptions Reply Brief at 8).

ii. Tiered Customer Charges

PowerOptions argues that a tiered customer charge rate structure based on maximum demand is not appropriate for residential or small commercial customers (PowerOptions Reply Brief at 3). In this regard, PowerOptions contends that these customers cannot appropriately adapt or respond to a tiered customer charge structure without having advanced metering, demand meters, or appropriate technology to know when they are reaching their peak use (PowerOptions Reply Brief at 4). Further, PowerOptions maintains that National Grid did not sufficiently demonstrate that using non-coincident peak demand actually reflects a customer's contribution to distribution system costs, and, as such, it is the appropriate tool for charging distribution rates (PowerOptions Reply Brief at 4, citing NECEC Brief at 11, 13).

Moreover, PowerOptions argues that the Company's Phase II proposal removes the link between a customer's energy conservation and seeing reduced charges on the electric distribution bill because a customer must maintain a year of reduced monthly use to drop to a lower tier (PowerOptions Reply Brief at 3). PowerOptions contends that the tiered customer charge proposal risks undermining one of the Commonwealth's energy policy goals of maximum deployment of energy efficiency (PowerOptions Reply Brief at 4, citing DOER Brief at 7). Further, PowerOptions claims that the delay in monetary savings from the implementation of energy efficiency measures inherent in National Grid's tiered customer charge proposal could discourage these investments and impact the Commonwealth's energy goals (PowerOptions Reply Brief at 4). Additionally, PowerOptions asserts that National Grid has not analyzed how the tiered customer charge proposal may affect the achievement of its three-year energy efficiency plan (PowerOptions Reply Brief at 4-5, citing DOER Brief at 7).

Finally, PowerOptions maintains that the Company's proposal is not consistent with the Department's "standard of review" (PowerOptions Reply Brief at 3). Based on all of these reasons, PowerOptions asserts that the Department should reject the Company's tiered customer charge proposal (PowerOptions Reply Brief at 3, 5).

iii. Seasonal Rate Design

PowerOptions supports the Attorney General's seasonal rate design proposal (PowerOptions Reply Brief at 5). PowerOptions maintains that it is easier for customers to understand than the Company's Phase II proposal and enables customers to respond to price signals (PowerOptions Reply Brief at 5). PowerOptions argues that there is a much stronger correlation between peak-season energy consumption and peak demand than the Company describes (PowerOptions Reply Brief at 5, citing Exhs. AG-SJR-1, at 17; AG-SJR-4). Thus, PowerOptions maintains that the Attorney General's seasonal rate design proposal links distribution prices to summer distribution peaks (PowerOptions Reply Brief at 5). According to PowerOptions, the seasonal rate design proposal is cost-based, results in reasonable bill impacts, is simple and understandable, improves efficiency and cost causation, and therefore, meets the Department's rate design goals (PowerOptions Reply Brief at 5, citing NECEC Brief at 30).

g. Company

i. Overview

National Grid argues that the appropriate regulatory forum to determine rate design is in a general rate case, based on the revenue requirement and cost studies used to establish "just and reasonable" rate design (Company Reply Brief at 83-84). According to the Company, its rate structure should consist of customer charges, demand charges, and consumption charges that are reflective of customer-related, demand-related and consumption-related costs, respectively (Company Reply Brief at 84). National Grid contends that its proposal is "the first step in a process towards an optimal rate design, which would include both customer and demand charges for each rate class" (Company Brief at 214).

Moreover, the Company maintains that its proposed rate design properly balances the Department's rate design goals: efficiency, simplicity, continuity, fairness, and earnings stability (Company Brief at 202, citing Exh. NG-PP-1, at 29; Company Brief at 211, 213-214). According to the Company, its rate design: (1) produces the desired revenue for each rate class determined in its allocation process; (2) generates revenue that is reasonably stable and predictable while reflecting cost-causation principles; (3) reflects the cost to serve and to ensure adequate revenue to the utility; (4) mitigates extreme bill impacts on customer groups; and (5) results in equalized rates of return amongst all rate classes pursuant to § 94I (Company Brief at 202, citing Exh. NG-PP-1, at 46-47). Therefore, the Company asserts that the Department should approve the Company's proposed rate design in this case (Company Reply Brief at 84).

The Company explains that its primary objective in its rate design proposal is customer equity and to design rates that reflect the actual relative cost to serve each customer (Company

Brief at 203, citing Exh. NG-PP-1, at 23; Company Reply Brief at 83). However, the Company argues that there are limitations in establishing the cost to serve customers and the ability to design rates that recover those costs (Company Brief at 212). In particular, National Grid contends that costs are determined for groups of homogeneous customers with similar cost-causation attributes, not for individual customers (Company Brief at 212, citing Exhs. NG-PP-1, at 39-41; AG-12-2). Further, the Company claims that the Department's rate design goals of simplicity, continuity, and earnings stability often lessen the cost-basis in rate design implementation (Company Brief at 212). Additionally, the Company maintains that it considers the cost and availability of meters in designing rates (Company Brief at 212).

The Company supports transparent and efficient rate designs that provide sufficient revenue to support the distribution system, motivate the appropriate behaviors, and assure fairness and equity among customers (Company Brief at 213). According to National Grid, both DG and non-DG customers impose demand on the distribution system and its associated services (Company Brief at 213). However, the Company asserts that distribution service provided to DG customers is being paid for, in whole or in part, by all customers through revenue decoupling and net metering credits[304] (Company Brief at 213). In this regard, National Grid notes that it recovers the bulk of distribution service costs through the volumetric portion of distribution rates (Company Brief at 213). Further, the Company contends that net metering allows DG customers to zero out bills and to build credits towards their cost for future electricity consumption (Company Brief at 214). The Company contends that this policy has enabled many customers to

304 The Company reports that net metering caps are over-subscribed, and it provided approximately $64 million of net metering credits to DG customers in 2015 (Company Brief at 215, citing Exhs. NG-PP-Rebuttal-1, at 19; DPU-5-3; Tr. 7, at 1043)

avoid payment for their use of the distribution system (Company Brief at 214). Therefore, the Company maintains that the current DG landscape and its rate design creates a growing cost-shift within the Company's service territory, while providing little benefits (Company Brief at 213-215, citing Exh. NG-PP-Rebuttal-1, at 37).

Finally, the Company argues that the price for distribution service should reflect the value and true cost of the service, and customers' bills should reflect each customer's demand for such service (Company Brief at 213). According to National Grid, current rate design does not properly attribute costs caused by customers with DG facilities to those customers, but its rate design proposal appropriately addresses cost responsibility for DG customers (Company Reply Brief at 83-84, 212). The Company contends that if rate design is not based on cost causation, customers that do not use DG facilities are cross-subsidizing those customers with DG facilities (Company Reply Brief at 83, 212).[305] Further, National Grid claims that the Limited Intervenors are employing delay tactics that ignore the impact on rates and cost recovery caused by the rapid development of DG facilities in Massachusetts (Company Reply Brief at 83).

ii. Demand Ratchets

National Grid argues that those opposing the Company's demand ratchet proposal do not dispute the ratemaking objective of demand ratchets, but rather, oppose the demand ratchets' effect on energy efficiency, solar DG, and storage (Company Brief at 226; Company Reply Brief

305 According to the Company, it collects most of its costs through usage charges (Company Reply Brief at 84). The Company contends that the usage of a customer with a DG facility behind-the-meter may drop or vary from the baseline used to establish rate design (Company Reply Brief at 84). Therefore, the Company maintains that the relationship between cost incurrence and revenue collection is broken and the recovery of costs is shifted to other customers (Company Reply Brief at 84).

at 92). The Company asserts that such opposition lacks merit (Company Brief at 227; Company Reply Brief at 93).

In particular, National Grid rejects any arguments that a demand ratchet delays payback periods for energy efficiency and demand reduction investments, and the Company instead notes that its demand ratchet analysis shows little impact on customer savings from the implementation of energy efficiency because approximately 70 to 75 percent of energy efficiency savings result from reductions in kWh use (Company Brief at 227, citing Exh. NG-PP-Rebuttal-1, at 28; Company Reply Brief at 93). Further, National Grid maintains that the record demonstrates that a demand ratchet has little impact on a customer installing energy efficiency or demand reduction technologies (Company Brief at 227, 228; Company Reply Brief at 93, 94). According to the Company, it calculated a \$200 to \$400 reduction, from total savings ranging from \$26,000 to \$57,000, in the first year of an energy efficiency investment, due to the demand ratchet (Company Brief at 227, citing Exh. DPU-15-16, Att. at 3-4; Company Reply Brief at 93). Moreover, the Company argues that with or without the demand ratchet, the customer will accumulate all of the annual savings associated with energy efficiency investments after the first investment year (Company Brief at 227-228; Company Reply Brief at 93-94).

Regarding the installation of a demand reduction investment (i.e., DG or storage), the Company maintains that customer savings on an installation that reduces 50 percent of kW and kWh billing determinants reduced savings by 2.6 percent for the first year (from approximately \$205,800 to \$193,800) as a result of the demand ratchet (Company Brief at 228, citing Exh. DPU-15-16, Att. at 5; Company Reply Brief at 94). Therefore, National Grid contends that demand ratchets will not cause a disincentive to invest in energy efficiency or demand reduction technologies (Company Brief at 228; Company Reply Brief at 94).

Further, the Company argues that a demand ratchet is reasonable and appropriate for Rate G-2 and Rate G-3 customers because it will assess demand charges based upon each customer's maximum demand during the year (Company Brief at 208; Company Reply Brief at 92). The Company notes that its system was designed and built to accommodate maximum aggregate demand of all customers at a single point in time (Company Brief at 226, citing Exh. NG-PP-1, at 56-57; Company Reply Brief at 92). Thus, the Company asserts that its proposal will better reflect a customer's contribution to coincident demand, and it will result in cost recovery more reflective of the costs that are incurred to serve that customer (Company Brief at 208, 226, citing Exh. NG-PP-1, at 56-57; Company Reply Brief at 92). Consequently, National Grid asserts that it has demonstrated that the demand ratchet for Rates G-2 and G-3 is reasonable, and that its proposal should be approved (Company Brief at 228; Company Reply Brief at 94).

iii. Tiered Customer Charges

National Grid argues that its Phase II rate design proposal is a reasonable change in rate structure to move rates for residential and small commercial customers toward the recovery of customer-related and demand-related costs to serve (Company Brief at 225; Company Reply Brief at 91). According to the Company, a higher customer charge for higher-use customers is a reasonable proxy to recover the higher demand-related costs imposed on the distribution system by these customers (Company Brief at 225; Company Reply Brief at 91). The Company asserts that its proposal is consistent with the Department's rate structure goals and objectives, and, therefore, it should be approved (Company Brief at 225; Company Reply Brief at 91).

According to the Company, a distribution system is sized and constructed to accommodate the maximum demand on the system at a single point in time, and, once constructed, distribution system costs are fixed in nature (Company Brief at 217, 218, citing Exhs. NG-PP-1, at 33, 38; Company Reply Brief at 85, 86). The Company maintains that a customer's monthly maximum kWh use during a 12-month period reflects the customer's contribution to total system demand and should be the basis for the customer's cost responsibility in rate design instead of a customer's monthly or annual kWh consumption (Company Brief at 217, 218, citing Exh. NG-PP-1, at 38-39; Company Reply Brief at 85, 86). Therefore, the Company contends that its Phase II rate design proposal better aligns the recovery of fixed distribution system costs than the current single customer charge for these rate classes and results in a more equitable contribution to costs by all customers on the basis of their size (Company Brief at 217, 218, citing Exh. NG-PP-1, at 32, 35; Company Reply Brief at 85, 86). Further, National Grid argues that a reduction in energy consumption does not necessarily result in a corresponding reduction in distribution costs (Company Brief at 218, citing Exh. NG-PP-1, at 32, 35; Company Reply Brief at 86). According to the Company, the Phase II rate design proposal is a reasonable proxy for a rate structure in which a fixed customer charge recovers the customer related cost to serve each customer and a demand charge based on customer size recovers capacity-related costs (Company Brief at 217, citing Exh. EFCA 1-1; Company Reply Brief at 85).

The Company disagrees with the argument that the adoption of the tiered customer charge would be inconsistent with § 141 (Company Brief at 222, citing Low Income Network Brief at 17-26; Vote Solar Brief at 22-23; Company Reply Brief at 88, citing Low Income

Network Reply Brief at 5-7; NECEC Reply Brief at 12-13; Vote Solar Reply Brief at 11-13). The Company argues that interpreting the statue to ban any rate design that would affect existing incentives for DG and energy efficiency is not consistent with the plain language of that statute (Company Brief at 222; Company Reply Brief at 88). Rather, according to the Company, a reasonable reading of the statutory language is that the Department is required to consider the impacts of the Company's proposed rate design along with the increased incentives that are provided to energy efficiency and on-site generation (Company Brief at 222 (emphasis in original); Company Reply Brief at 88-89). The Company maintains that the Department must balance the various interests (i.e., rate design and incentives for energy efficiency and DG), which the Company advocates for in its rate design proposals (Company Brief at 222; Company Reply Brief at 89).

Further, in response to the argument that the tiered customer charges do not reflect the demand-related costs that individual customers put on the system and that they do not consider the timing of the customer's non-coincident peak and peak demand, the Company asserts that existing demand charges are based on a customer's maximum demand (Company Brief at 220; Company Reply Brief at 87). For example, the Company argues that demand charges for C&I customers are assessed on the customer's maximum kW because it represents the customer's potential to contribute to the capacity requirements of the distribution system (Company Brief at 220-221, citing Exh. NG-PP-Rebuttal-1, at 14; Company Reply Brief at 87, citing Exh. NG-PP-Rebuttal-1, at 14). Therefore, the Company asserts that a demand charge designed to recover demand-related distribution costs billed to the customer on maximum monthly demand is not new or unreasonable (Company Brief at 221; Company Reply Brief at 87).

Further, in response to the argument that the tiered customer charge proposal is not an improvement over the current rate design, the Company argues that its detailed analysis refutes the claim (Company Brief at 223, citing Exh. NG-PP-Rebuttal-2; Company Reply Brief at 89 citing Exh. NG-PP-Rebuttal-2). According to the Company, the analysis comparing bill charges resulting from: (1) the existing rate design; (2) the proposed residential Phase I rate design; (3) the proposed residential Phase II rate design reflecting tiered customer charges; and (4) a rate design that includes separate customer and demand charges, demonstrates that, for both high- and low-load factor customers, its Phase II proposal charge more closely approximates the rates based on separate customer and demand charges (Company Brief at 223, citing Exh. NG-PP-Rebuttal-1, at 12; Company Reply Brief at 89). In addition, National Grid argues that its Phase II rate design proposal does not produce monthly bills that are significantly different from those under either the current rate structure or its proposed Phase I rate design (Company Brief at 223; Company Reply Brief at 89). Therefore, the Company asserts that its Phase II proposal fulfills the Department's rate continuity goal (Company Brief at 223; Company Reply Brief at 89).

National Grid also rejects any arguments that its proposed tiered customer charge structure is confusing and provides insufficient price signals (Company Brief at 224, citing DOER Brief at 8; EFCA Brief at 14-15; NECEC Brief at 14-15; Vote Solar Brief at 15-19; Company Reply Brief at 90, citing DOER Reply Brief at 4; EFCA Reply Brief at 11-12; NECEC Reply Brief at 10-12; Vote Solar Reply Brief at 8-9). The Company contends that such arguments are contradictory to the notion that customers demand more time varying rates (Company Brief at 224, citing DOER Brief at 8; EFCA Brief at 14-15; NECEC Brief at 14-15; Vote Solar Brief at 15-19; Company Reply Brief at 90, citing DOER Reply Brief at 4; EFCA Reply Brief at 11-12; NECEC Reply Brief at 10-12; Vote Solar Reply Brief at 8-9). In this regard, the Company argues that although its proposal is based on the concept that customer demand underlies the basis for the tiered customer charge, the actual structure of the rates (i.e., a customer charge and a per-kWh rate) does not change (Company Brief at 224-225, citing Exh. NG-PP-Rebuttal-1, at 30; Company Reply Brief at 90-91).

Moreover, while National Grid acknowledges that customers might not be familiar with the concept of demand, the Company argues that customers understand the implications on the distribution system resulting from changes in electricity consumption (Company Brief at 224, n.44, citing docket D.P.U. 10-82, evaluation report of the Company's Smart Energy Solutions Program; Company Reply Brief at 90 n.20). Further, the Company claims that its outreach and education program will resolve any customer confusion about its Phase II rate design proposal (Company Brief at 225; Company Reply Brief at 91). In particular, the Company maintains that it proposed a six month delay in its Phase II rate design effective date "to educate customers on the reason behind and determination of the tiered customer charges, including changes to their bills and ways to reduce usage to take advantage of tiers with lower customer charges" (Company Brief at 225, citing Exh. NG-PP-Rebuttal-1, at 31; Company Reply Brief at 91).

iv. Seasonal Rate Design

National Grid opposes the alternative seasonal rate design proposal recommended by the Attorney General and others, as the Company claims that there is no cost basis for the 15-percent differential between summer and winter rates (Company Brief at 224; Company Reply Brief at 90; see Attorney General Brief at 137; Attorney General Reply Brief at 72, 76; Acadia Center Brief at 17-18; Acadia Center Reply Brief at 11; NECEC Brief at 29-30; NECEC Reply Brief at 3, 6, 10, 12, 13). According to the Company, "while there is little data identifying a peak load during the non-summer months of October through May, many feeders may experience non-summer peak demands that are very close to their summer peak demand" (Company Brief at 223-224, citing Exh. VS-2-12; Company Reply Brief at 89). Further, the Company contends that a summer-peaking feeder may become winter peaking during extremely cold weather, and that transition reduces the differences between summer and winter peak demands (Company Brief at 224; Company Reply Brief at 89-90). Further, National Grid claims that increasing solar generation affects summer demand far greater than winter demand, further increasing the probably of peak loads shifting from the summer months to the winter months in the future (Company Brief at 224; Company Reply Brief at 90). Therefore, the Company argues that "a system-wide reduction in coincident peak demand may not result in a commensurate reduction in actual or forecasted peak demand for each feeder" (Company Brief at 224; Company Reply Brief at 90). Finally, the Company asserts that setting a summer rate 15 percent higher than a winter rate will produce arbitrarily higher net metering credits (Company Brief at 224; Company Reply Brief at 90).

6. Analysis and Findings

In ruling on the Company's rate design proposals, the Department considers its rate design goals: to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 15-80/D.P.U. 15-81, at 294; D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341; D.P.U. 09-39, at 401. In practice, meeting the goal of efficiency should involve rate structures that provide strong signals to consumers to decrease energy consumption in consideration of price and non-price social, resource, and environmental factors. D.P.U. 15-80/D.P.U. 15-81, at 295; D.P.U. 12-25, at 445.

a. Demand Ratchets

DOER, EFCA, AIM and TEC, and PowerOptions, oppose the Company's demand ratchet proposal. The Company previously proposed to implement demand ratchets, and the Department denied the Company's request. Massachusetts Electric Company, D.P.U. 85-146, at 68-69 (1986). In denying the demand ratchet proposal, the Department found that demand ratchets can, in an uneconomic manner, provide no incentive to reduce demand beyond the class or system peak and little incentive to reduce kWh use. D.P.U. 85-146, at 69. Moreover, we determined that a demand ratchet distorts the price signal to the customers and discourages customers from investing in load control equipment that would otherwise be cost-effective. D.P.U. 85-146, at 68; see also D.P.U. 84-145-A at 125. Further, the Department has found that demand ratchets are inappropriate because they distort incentives to conserve electricity and could unfairly impose higher costs on certain customers. Western Massachusetts Electric Company, D.P.U. 94-101/95-36, at 50 (1995); D.P.U. 92-78, at 188; Western Massachusetts Electric Company, D.P.U. 86-280, at 196 (1987); D.P.U. 84-25, at 199.

Further, the Company did not present any particularly compelling argument that would persuade the Department to alter its precedent on this matter.[306] In particular, the Department finds that the Company failed to provide sufficient evidence to demonstrate that a customer would have any incentive to reduce their demand after it reaches its annual peak demand. Therefore, we find that the Company's proposed demand ratchet is inconsistent with the aforementioned Department precedent, as well as the Department's goals of efficiency and fairness. As such, the Company's demand ratchet proposal is denied. Accordingly, the Department directs the Company in its compliance filing to revise its proposed demand charges for Rates G-2 and G-3 to eliminate the demand ratchet component. Instead, the Company shall design the demand rates consistent with the definition of billing demand found in its currently effective Rates G-2 and G-3 tariffs, M.D.P.U. Nos. 1152 and 1153 (respectively for MECo) and M.D.P.U. Nos. 526 and 527 (respectively for Nantucket Electric).

b. Tiered Customer Charges

National Grid's tiered customer charge proposal is premised on the Company's position that under its current rates there is a shift in cost recovery from DG customers to non-DG customers (Exh. NG-PP-Rebuttal-1, at 53). The tiered customer charges are designed to mitigate that cost-shift by using a customer's highest monthly energy use as a proxy for that customer's peak demand, thereby employing a rate design that captures the cost that a customer imposes on

306 The Department recognizes that it accepted demand ratchets as a reasonable resolution of the issue of undue discrimination in allowing standby rates, but only in the context of a Settlement Agreement between NSTAR Electric, DOER, AIM, CLF, the Joint Supporters and SEBANE. NSTAR Electric Company, D.T.E. 03-121, at 42 (2004). In approving the Settlement Agreement, the Department's decision in that proceeding was not intended to represent a fully litigated review on the merits resulting in a wholesale change in rate making policy. D.T.E. 03-121, at 42 n.16.

the distribution system from the customer's individual peak demand (Exhs. NG-PP-1, at 32-35; NG-PP-Rebuttal-1, at 10; DPU-9-14). The Attorney General, DOER, the Low Income Network, the Limited Intervenors, and PowerOptions oppose the Company's tiered customer charge proposal.

The Company purports that "DG customers may contribute significantly less to support the distribution system as a result of their reduced kWh usage, thereby shifting the recovery of distribution system costs to all non-DG customers" (emphasis added) (Exh. NG-PP-1, at 28). The Company has not quantified the amount of costs attributable specifically to DG customers and has not quantified the distribution system benefits associated with DG customers in its service territory (Exhs. NG-PP-Rebuttal-1, at 22; DPU-29-6, at 2; LI-1-10, at 1; Tr. 5, at 620). Other than quantifying net metering credits and citing to current rate design, the Company did not substantiate its cost-shift assumption with reasonable analysis and quantitative record evidence (Exhs. NG-PP-Rebuttal-1, at 19; DPU-5-3, Att.). As such, the Department is not persuaded that a cost-shift from DG customers to non-DG customers, in fact, exists. Therefore, we find that the basis of the Company's tiered customer charge proposal is not sufficiently supported.

Further, § 141 states, in part: "[i]n all decisions or actions regarding rate designs, the [D]epartment shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation." The Company's tiered customer charge proposal shifts cost recovery away from the volumetric, per-kWh charges, causing kWh rates to decrease (Exh. NG-PP-1, at 32). As volumetric, per-kWh rates decrease, customers' incentives to install energy efficiency and on-site generation