COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

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PETITION OF BOSTON GAS COMPANY D/B/A	:	
NATIONAL GRID FOR APPROVAL OF AN	:	
INCREASE IN BASE DISTRIBUTION RATES	:	D.P.U. 20-120
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DIRECT TESTIMONY OF
BENJAMIN W. GRIFFITHS

on Behalf of
the Massachusetts Office of Attorney General

Exhibit AG-BWG-1

March 26, 2021

Hearing Officer Marc Tassone

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1. Introduction

Q. Please provide you name, title, and organization description.

A. My name is Benjamin Griffiths. I am an Energy Analyst working for the Massachusetts Office of the Attorney General ("AGO") in the Energy and Telecommunications Division. My business address is One Ashburton Place, Boston, MA, 02108. The Massachusetts Attorney General represents the Commonwealth of Massachusetts, the public interest, and the people of the Commonwealth with respect to utility industry matters that affect consumers in Massachusetts. She is authorized expressly by statute to intervene on behalf of public utility ratepayers in proceedings before the Commission.

Q. What is the purpose of your testimony in this case?

A. I have been asked by the AGO to review the marginal cost study ("MCS") filed by Boston Gas Company d/b/a National Grid ("National Grid," "NG," or the "Company").

Q. Please describe your relevant work experience and education.

A. My primarily responsibility at the Massachusetts AGO is to provide qualitative and quantitative analysis of cases before the Department of Public Utilities ("Department"), as well as proposals before Independent System Operator ("ISO") New England and the Federal Energy Regulatory Commission ("FERC").

I joined the AGO in 2018. Between 2012 and 2015, and again in 2017–2018, I was employed by Resource Insight, Inc., a Massachusetts-based consulting firm specializing in the regulation of electric and gas utilities, providing technical and policy analysis and advice. There, I worked on resource planning, forecasting, energy efficiency, and utility rate design issues. In 2017, I received an M.S. in Energy & Earth Resources from the University of Texas at Austin. I have taken coursework in statistics, mathematical statistics, probability, modeling and numerical techniques. I have authored or co-authored reports, whitepapers, and a peer-reviewed journal article on various utility-related topics, which are listed in my curriculum vitae attached to this testimony as Appendix A.

Pertaining to marginal costs in New England, I have previously assessed marginal energy system costs as part of the Avoided Energy Supply Costs in New England reports in 2013 and 2018. In those reports, I developed various statistical models to assess marginal costs of electricity, natural gas, and oil supply—including regression and time-series models.[1] I have also filed testimony in several FERC dockets related to economic modeling. My complete curriculum vitae is attached to this testimony as Appendix A.

Q. How is your testimony organized?

A. Section 2 summarizes my findings on the Marginal Cost Study. Section 3 describes the purpose of a marginal cost study and provides a short discussion on the Department's standard and precedent relating to marginal cost studies. Section 4 provides a detailed

[1] *See* Synapse Energy Economics (P. Knight, M. Chang, D. White, N. Peluso, F. Ackerman, J. Hall), Resource Insight (P. Chernick, S. Harper, S. Geller, B. Griffiths), *Avoided Energy Supply Components in New England: 2018 Report*, prepared for Avoided-Energy-Supply-Component 2018 Study Group, at Chapter 9, Appendix K, available at https://www.synapse-energy.com/project/aesc-2018-materials.

discussion of several deficiencies I have identified in National Grid's MCS. Section 5 offers my proposed alternative calculations for the Company's distribution capacity-related marginal costs which can stand-in for the Company's Exhibit NG-MFB-2 and NG-MFB-3. Section 5 also revises the Company's Exhibit NG-MFB-6 to reflect my alternative marginal cost estimates.

2. Summary

Q. Please summarize your conclusions about the regression analysis conducted by the Company as part of the MCS.

A. I conclude that the Company did not follow best practices with regard to econometric modeling, that there is an overreliance on dummy variables (contrary to Department guidance), and that there are mis-specifications of autoregressive processes in two of the three regressions assessed. For this reason, I am sponsoring alternative regression analyses to substitute for Exhibits NG-MFB-2 and NG-MFB-3.

Q. Please summarize your estimate of marginal cost per Dth delivered.

A. I developed alternative regression analyses for distribution plant-related costs, distribution operations expenses, and distribution maintenance expenses. These regressions seek to correct for deficiencies that I have identified the Company's Exhibits NG-MFB- 2 through NG-MFB-6. My proposed alternative regressions were developed in accordance with the directives and standards of the Department related to marginal cost studies. As shown on Exhibit AG-BWG-4, page 2, and supported by the remainder of my testimony and exhibits, I have estimated that the annual loss-adjusted marginal distribution capacity-related cost of service at a customer's meter is $240.05 per Dth of Design Day Demand, and $0.2983 per Dth of delivery quantities. By contrast, the Company's estimated annual loss-adjusted marginal distribution capacity-related cost of service at a customer's meter is $148.47 per Dth of Design Day Demand, and $0.00 per Dth of delivery quantities.

The marginal capacity cost per Dth of Delivery Quantities by rate category, as tabulated in Exhibit AG-BWG-4, page 2, is shown in the table below:

Table 1: Marginal Capacity Cost per Dth of Delivery Quantity, by Rate Category

	R1/R2	R3/R4	G&T 41/42/43/44	G&T 51/52/53/54
Normalized Usage - Annual Total (Dth)	1,387,315	70,691,370	42,276,860	20,179,114
Normalized Peak Day Demand	10,692	801,149	509,483	136,261
Marginal Capacity cost per Dth of Delivery Quantity	$2.21	$3.10	$3.28	$1.97

Below is a discussion of my analysis and how I derived my proposed marginal costs.

3. Marginal Cost Study ("MCS") and Department Standards and Guidance

Q. Have you reviewed the MCS prepared by Company witness Melissa Bartos?

A. Yes, I have reviewed the MCS provided in the Company's Exhibits NG-MFB-2 through NG-MFB-6 and the direct testimony of National Grid witness Bartos. Exh. NG-MFB-1. I have also reviewed several recent Department decisions on marginal cost studies including *Boston Gas Company and Colonial Gas Company*, D.P.U. 17-170 (2018), *NSTAR Gas Company*, D.P.U. 14-150 (2015), and *New England Gas Company*, D.P.U. 10-114 (2011).

Q. What is your understanding of the purpose of a marginal cost study?

A. 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. 17-170, at 319–20. More narrowly, it is my understanding that the primary purpose of a gas utility MCS is to determine distribution capacity-related marginal costs. Marginal cost studies are used by gas companies to establish the minimum cost of providing service and are a key factor in evaluating special contracts.

Q. What are the Department Standards and Precedents for an MCS?

A. I generally agree with National Grid witness Bartos on the elements of an MCS, as described in Exhibit NG-MFB-1. These are as follows:

1. The marginal cost study should incorporate sufficient detail to allow a full understanding of the methods used to determine the marginal cost estimates;
2. The marginal cost study should not include estimates of marginal production, transmission, or customer costs;
3. The estimates of marginal costs should use appropriate historical data that is reliable, as required by Department precedent;
4. The estimates of marginal costs should be based on proper econometric techniques to provide statistically reliable estimates;
5. The estimates of marginal costs should be based on multi-variate regression techniques; and
6. The marginal cost study should include the results of appropriate diagnostic tests to ensure the appropriateness of the regressions in the marginal cost study.

Exh. NG-MFB-1, at 4–6 (citing *NSTAR Gas Company*, D.P.U. 14-150); *see NSTAR Gas Company*, D.P.U. 14-150, at 377–78.

With regards to the regressions themselves, the Department has also offered some guidance related to the use of multi-variate regression techniques, data underlying the regressions, statistical tests to assess (and correct for) multicollinearity, autocorrelation, error normality, and the use of dummy variables. *See* D.P.U. 17-170, at 323–25.

4. Concerns with the Company-Sponsored MCS

Q. Do you agree with all of the assumptions and methods used in the MCS?

A. No, I do not. While I agree with the techniques that the Company used to assemble its datasets and perform many specific statistical tests (*e.g.*, for multicollinearity or coefficient significance), I do not agree with the approach used by the Company to specify regression models or the Company's approach to control for autocorrelation. More specifically, I have identified four issues with the MCS. My four primary concerns, addressed in more detail below, are:

1. National Grid failed to provide any theoretical justification for its selected model specifications;
2. National Grid failed to consider certain variables that could help explain distribution system costs, risking "omitted variable bias;"
3. National Grid overly relied on statistically significant but irrelevant dummy variables, autoregressive terms, or interaction terms, contrary to prior Department requirements; and
4. National Grid misapplied time-series models, leading to incorrect and spurious autoregressive terms, and resulting in inaccurate and unreliable results.

I discuss each of these issues in greater detail below.

Q. What are your general concerns with how the Company specified its regression models?

A. A model's specification is the first, and in many ways, the most important step of a regression analysis. A model's specification is, essentially, a statement about the causal relationship between independent and dependent variables. A model's specification refers to the determination of which independent variables should be included or excluded from a regression equation. The estimation and interpretation of model coefficients are only as good as the model specification which generated them. For example, a model which includes many spuriously correlated variables may have high statistical significance but provide little or no predictive value.[2]

Contrary to standard econometric modeling practices, at the time the model was specified, the Company did not carefully consider the underlying mechanisms which explain demand-related costs. As noted in Jeffery Wooldridge's *Introductory Econometrics: A Modern Approach* (5th Ed., 2013), "[f]or the most part, econometric analysis begins by specifying an econometric model, without consideration of the details of the model creation. . . . Once an econometric model . . . has been specified, various *hypotheses* of interest can be stated in terms of the unknown parameters." Wooldridge, at

[2] There are many well-documented spurious correlations that are significant, but not relevant. For example, using U.S. Department of Agriculture and National Science Foundation datasets, Tyler Vigen shows that per capita consumption of mozzarella cheese is 95.86% correlated with civil engineering doctorates awarded over the period 2000-2009. Tyler Vigen, *Spurious Correlations*, available at https://www.tylervigen.com/spurious-correlations. While possible, it seems unlikely that the cheese consumption is *causing* those doctorates, or vice versa.

5; *see* Ramu Ramanathan, *Introductory Econometrics with Applications* (5th Ed., 2002), at 113. For the purposes of marginal costs, a likely relationship between costs and various independent factors (*e.g.*, peak demand, total sendout, or a labor dispute) can be described without collecting a single piece of data.

Rather than adhering to standard econometric modeling practices and specifying the expected relationship between costs and demand before modeling, the Company appears to have relied on *ad hoc* data-mining techniques to increase the predictive power of their models.[3] By relying on *ad hoc* data-mining technics, the Company in effect improves each model's goodness-of-fit without formally explaining the relevance of each variable included. This approach increases the risk of spurious correlation and may reduce the explanatory power of its models to describe marginal costs.

National Grid witness Bartos outlines her "general approach" to perform the MCS model specification thus: "I [] [s]ystematically tested different supportable combinations of explanatory variables, different forms of explanatory variables, and different functional forms of regression equations as appropriate[.]" Exh. NG-MFB-1, at 11; *see* Exh. AG-9-6(d)). Or put more simply, the Company seeks to develop regressions by adjusting various parameters until it gets results that seem plausible. This description from witness Bartos of her "general approach" makes it clear that the Company has a

[3] *See, e.g.*, Exh. NG-MFB-1 at 9 ("What I could not reasonably determine before performing the analyses was the exact form of the explanatory variable that would have the greatest explanatory power.") (emphasis in original).

systematic technique only in as much as it is a "system"—an approach—by which to develop its regressions. Contrary to best practices, these regressions appear to have been tuned by hand (*e.g.*, adjusting dummy variables to maximize goodness-of-fit values such as the R^2 metric[4]). *See* Exh. AG-9-11I. As noted in Ramanathan, "data mining to find the 'best fit' should be avoided because it often leads to the substantiation of any hypothesis one might think of, however contradictory such substantiations might be. Mechanical criteria should not be applied blindly without regard to theory or some understanding of the underlying behavior." Ramanathan, at 186. The inclusion of many unsubstantiated and logically dubious variables, as discussed below, are hallmarks of this kind of adverse data mining.

Q. Do you have any concerns that certain variables were unreasonably omitted from, or underutilized in, the Company's analysis?

A. Yes, I am concerned that the Company omitted sendout-related variables and failed to comprehensively investigate sendout-related variables, thus failing to consider terms that could more accurately explain marginal cost. While demand-related terms are certainly plausible cost drivers and are appropriate to include in the analysis, the total volume of gas used on the system is also a plausible cost driver and is also appropriate to include in the analysis. However, the Company does not appear to have comprehensively tested regressions which included both demand and sendout terms in the development of its

[4] R^2 is the ratio of the explained variation compared to the total variation. It can be interpreted as the *fraction of the sample variation in y that is explained by x*.

regression analyses. In discovery, in response to information requests from the AG, the Company did rerun certain regressions, adding in sendout terms *post hoc*. *See, e.g.*, Exhs. AG-33-1, -2, and -3. The Company did not test any regression equations which omitted a demand-related term. *See* Exhs. AG-9-9(c); AG-9-10(c).

In other contexts, the Department has recognized that demand-related costs are a function of both peak-demand and sendout. For instance, National Grid's current "proportional responsibility" ("PR") demand-allocator is a function of both metrics. *See* D.P.U. 17-170, Exh. NG-PP-1, at 32 (stating that Boston Gas Company and Colonial Gas Company "allocated the capacity or demand-related distribution costs based on the resulting class-by-class responsibilities from applying the [PR] method."); D.P.U. 17-170 at 319 (accepting the methodology in the ACOSSs); *see also* NARUC, *Gas Distribution Rate Design Manual*, 1989, at 27-28 (providing a related allocation method called "average and peak" that also allocates demand-related costs as a function of demand and sendout). It is concerning that such a plausible cost-driver—the amount of gas sold—does not appear to have been seriously investigated.

Omitting logically relevant variables—such as total sendout—generally leads to "omitted variable bias." If a relevant variable is omitted, the coefficient of every other variable will be affected unless the omitted variable happens to be perfectly uncorrelated with the included predictors, creating a set of results which may not be reliable. Moreover, as noted in Ramanathan, "[t]he estimated variance of the regression coefficient of an included variable will generally be biased, and hence tests of hypotheses are invalid." Ramanathan, at 166; *see* Wooldridge, at 87–92. To put a finer point on it, the Company's reliance on t-tests to assess statistical significance is only reasonable if the model specification included all relevant variables. *See* Exh. NG-MFB-1, at 12. If a relevant variable is not included, then the MCS results may not be accurate. Because sendout is obviously relevant, but not included in the Company's regressions, the MCS results may not be accurate.

Q. What are your concerns about the Company's excess reliance on statistically significant but irrelevant dummy variables, autoregressive terms, or interaction terms?

A. I have two concerns with the Company's reliance on dummy variables. First, adding dummy variables, even statistically significant dummy variables, can reduce the predictive power of a regression model. Second, overreliance on dummy variables reduces the salience of variables that *are* theoretically relevant. The Department has "caution[ed]" another utility against "extensive use of [dummy variables and autoregressive terms] [because they] may not lead to the development of a model with the best predictive power." D.P.U. 10-114, at 355. Models that include many free variables—dummies, non-explanatory variables, spurious correlations, and the like—risk false precision. As the polymath John von Neumann once noted, "with four parameters I can fit an elephant, and with five I can make him wiggle his trunk."[5]

[5] Freeman Dyson, *A meeting with Enrico Fermi*, *Nature* 427**,** 297 (2004), available at https://doi.org/10.1038/427297a.

In Exhibits NG-MFB-2 through NG-MFB-3, the Company repeatedly utilizes unsubstantiated dummy variables to improve model fit. For example, the Company includes dummy variables for the years:

- 2009, 2013, 2018, and 2013–2019 (Exh. NG-MFB-2-GRID p1: Capital Additions);
- 2001–2019, 2013–14, 2018, and 2019 (Exh. NG-MFB-3-GRID p1: Operations Expense);
- 2008, 2009, 2010, 2016, 2018–2019 (Exh. NG-MFB-3-GRID p2: Maintenance Expense).

Note that the years being controlled through dummy variables are not consistent between these various models.

The Company employs dummy variables and dummy-like variables with great frequency. In Exhibit NG-MFB-2, four of the six exogenous explanatory variables are dummies; in Exhibit MFB-3 p1, four of the six are dummies; and in Exhibit MFB-3 p2, five of the seven are dummies.

While some of these dummy variables have a clear interpretive role and are appropriately included, most do not have a clear interpretive or causal role. With the exception of dummy variables controlling for the 2018–2019 labor dispute, justified because labor issues are likely to affect plant investments and costs (*see* Exh. NG-MFB-1, at 10), none of the dummies are explained.[6]

Some regressions also include interaction terms which function as dummy-like variables. For example, the regression on operations expense includes a variable for Feet of Main for the 2001–2019 period. Exh. NG-MFB-3 p1. Although these interaction terms are not actually dummy variables, these terms *function* similarly to dummy variables because the total amount of pipe on the system has remained relatively stable over the past 20 years.[7]

The justification for and interpretation of these dummy-like variables can also be challenging. For example, in response to AG-9-10(f), the Company states that it includes a variable related to cast-iron main for the years 2005–2019 because the variable is "statistically significant and logically related to distribution maintenance expenses[.]" Exh. AG-9-10(f). From an interpretation standpoint, the inclusion of this variable posits that there is something germane about the total amount of cast-iron main on the system—but only for the past 15 years; before then, the total amount of cast-iron main on the system is assumed to have no effect. Why? The Company does not explain why cast-iron pipe installed between 2005 and 2019 warrants inclusion. The Company

[6] National Grid witness Bartos notes that acquisitions and mergers, as well as labor disputes, may lead to "structural shifts" which warrant the use of dummy variables. Exh. NG-MFB-1 at 10. However, the merger dates noted—1999, 2000, and 2007—are not controlled for in any of the dummy periods noted above.

[7] *See* "Sum_Main_ft" variable in Att. AG-8-2-3 (Confidential).

similarly did not explain why it did not consider or model variables related to other time periods, or other types of mains. Accordingly, the Company cannot say with certainty that the variables they did include are the most relevant, even *post hoc*. Perhaps other years or other types of pipes would have offered more explanatory value, even if it is not clear that any of these variables would have been relevant. S*ee* Exh. AG-9-10(f) (indicating that the Company did not check the potential relevance of all other pipe/year combinations).

Including variables which lack theoretical basis can adversely affect model results, even when those variables are statistically significant. The regressions run by National Grid relate to a relatively small number of years (around 30). Adding a dummy favorable for a single year will effectively "lock" that year's value in place—i.e., the estimated value equals the observed, historic value. This increases the model's ability to explain observed data, but it does not necessarily increase its ability to describe the real world or marginal costs in the years to come.[8]

[8] *See* Ramanathan, at 152 ("In general, simpler models are recommended for two technical reasons. First, the inclusion of too many variables makes the relative precision of individual coefficients worse. . . . Second, the resulting loss of degrees of freedom would reduce the power of tests performed on the coefficients. Thus, the probability of not rejecting a false hypothesis (type II error) increases as the degrees of freedom decrease. Simpler models are also easier to comprehend than complex models.").

Q. What are your concerns with the time-series modeling conducted by the Company?

A. I have two concerns with the time-series modeling. First, the manner by which the Company "differenced" its distribution plant-related cost data may lead to model overfitting and reduced explanatory power of demand terms. Exh. NG-MFB-2 p1. The Company's erroneous Autoregressive, Integrated [Difference], Moving Average ("ARIMA") model specification may also discount the predictive power of a more parsimonious models. Second, it appears that the Company corrected for auto-correlation after it developed its model rather than beforehand—leading to spurious results.[9]

When conducing its time-series modeling, the Company relied on a common ARIMA model framework.[10] These models can account for non-stationary time-trends and autoregressive terms. *See* Exh. NG-MFB-1, at 11.

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[9] If you check and control for autoregression *after* adding exogenous variables, it is, in effect, suggesting that the autoregression affects the *residuals* rather than the autoregressive feature of the independent variable itself. Or in a slightly different framing, models which control for autoregressive features using dummy variables may inappropriately attribute explanatory power to those variables rather than the autoregressive process itself. Because some tested independent variables express the typical hallmarks of autoregression this should be corrected for at the beginning.

[9] As discussed in Section 5.2, the ACF and PACF values for the independent variable in Exhibit NG-MFB-2 do not suggest the need for an autoregressive term with lag of four (AR(4) term). However, the residuals after adding the various exogenous coefficients suggest that there is a possible autoregressive element at lag 4.

[10] Attachment AG-8-2-2 (CONF) lists the model type as an ARIMA(4,0,0), aligning with the results presented in Exhibit NG-MFB-2, including the lagged AR(4) term.

Q. Please elaborate on your first concern about how the Company conducted "differencing" in its time-series modeling?

A. The Company's first time-series regression concerns distribution plant-related costs. The goal of this model is to assess how plant-related costs relate to demand (and other variables). Rather than running a simple regression of total plant costs versus normalized demand, the Company runs this regression by modeling *incremental* (year-over-year change) in plant costs as a function of year-over-year change in normalized peak demand.

While the Company does not explain why it chose this functional form, I assume it was in order to meet the key assumption of ARIMA models, namely that data are "stationary." [11] Stationary data move around a constant average value. Many time-series are "non-stationary," meaning that the values continue to increase (or decrease) over time. It should come as no surprise that plant-related costs have consistently *increased* over the past thirty years. The traditional way that a non-stationary time-series is made stationary is to "difference" the dataset and a common way to do that is to subtract one year's value from the next. The Company appears to have used this approach, but elected to difference the data *outside* of the ARIMA model. ARIMA models can have the built-in ability to "difference" a dataset so as to make it stationary (the "I" in ARIMA stands for integrated differencing). While the method of differencing distinction may seem trivial, it leads material differences in model development and interpretation.

[11] *See* Box, Jenkins, Reinsel & Ljung's *Time Series Analysis: Forecasting and Control* (5th Ed; 2016), Chapter 4 (discussing ARIMA models and their assumptions).

Total distribution plant cost and normalized peak demand are both consistently increasing with time—and have for the past thirty years.[12] From year-to-year, however, the trend varies. In some years, plant costs go up a little faster than usual; in other years, the costs go up a little more slowly. The same is true for normalized demand. These year-to-year variations are real, but if you were to plot the *total* costs over the past thirty years, they would be hard to observe in practice.

The issue with the Company's approach to differencing relates to this distinction. Exhibit NG-MFB-2 seeks to fit a curve to change in plant costs based on change in demand, essentially trying to account for every little change in the *rate* of plant additions when annual costs went up a little faster than usual or up a little slower (costs were always going up in absolute terms). By focusing on these variations, rather than the overall trend, the model needs to find explanations for all the wiggles that might be caused for unimportant reasons (*e.g.*, the vagaries of the calendar or a bad winter that slowed down construction work). Analysis of year-to-year variability distracts focus from the *overall* relationship between demand and cost. To lean on a proverbial phrase, the Company's modeling approach might be mistaking the contours of each tree for the forest as a whole.

Methodologically speaking, the company should have differenced *inside* the ARIMA model rather than *outside* of it. ARIMA models have this functionality built in

[12] *See* the "Comb_Ch_Norm" variable and, implicitly, the "RI_CapAd" variable in Att. AG-8-2-3 (CONF).

for a reason. Had the Company done so, it would have created a model that explains how *total* costs are a function of normalized demand, and the Company would have been able to predict how total costs vary over time based on demand and other factors. This, in turn, would have measured goodness-of-fit metrics, such as R^2, by the model's ability to explain overall cost levels rather than changes in costs. A more parsimonious model, which sought to explain the trend rather than each wiggle, might show very good fit for total costs, but might poorly capture the idiosyncratic variation.

For example, imagine a process where costs increase every year by $100, plus or minus $10. Year 1 costs are $100 (Total = $100), Year 2 costs are $90 (Total = $190), Year 3 costs are $110 (Total = $300), and so on. The real trend (the true cost generating process) is simple: costs are increasing at $100/Year, plus some error/random variation. If you try to create a model that explains why costs were exactly $100, $90, and $110, however, it would be easy to get caught up in the minutia and lose sight of the true cost function. The Company did the latter, rather than the former.

Unfortunately, I could not find a time-series within the Company's source data files (in response to AG-8-2) which tabulated the *<u>total</u>* level of distribution plant-related costs (as opposed to their annual change), so I could not test what effect integrated differencing would have made in practice. I suspect, however, that a simple model with the correct specification would indicate that peak-demand-related costs are materially higher than those estimated by the Company.

Q. Please elaborate on your second concern about the Company's time-series modeling, related to the specification of autoregressive terms?

A: It appears that the Company corrected for auto-correlation after it developed its model rather than beforehand—leading to potentially spurious results. If an autoregressive process is identified in a dependent variable, it should be accounted for in the model's specification from the start.

As discussed in Section 5.2, the Company's distribution plant cost variable shows clear indication of auto-correlation with a lag of one (*i.e.*, AR(1)). An AR(1) term means that the costs in one year are partially a function of the costs in the immediately preceding year—a relatively common phenomenon. The Company does not include an AR(1) term in its regression but does include an autoregressive term with lag of 4 (it does not include lags of 1, 2, or 3 years). From an interpretation standpoint, the Company's model is claiming that incremental plant costs of one year are a function of incremental plant costs incurred exactly four years prior. For example, the model suggests that incremental plant costs in 2018 are partially a function of costs in 2014, but costs in 2018 are not partially a function of costs in 2013 or 2015. Similarly, incremental plant costs in 2019 are partially a function of costs in 2015, but not in 2014 or 2016. And so on. What explains these peculiar quadrennial costs?

When adding an AR(1) term, the Company's AR(4) term becomes spurious and many of the included coefficients are no longer significant. This finding suggests that the ARIMA model used in Exhibit NG-MFB-2 is technically mis-specified and that the results may be spurious—that the autoregressive term is only needed due to the effect of adding other exogenous variables. This mis-specification helps account for the AR(4) term with its unintuitive interpretation: spurious correlation, akin to accidental (or incidental) rhyming in the data.[13] As noted below, the reverse problem also occurs: there is one regression where an autoregressive term should be added but none is included. *See infra*, Section 5.4. Mis-specifying a time-series model can result in false precision by capturing trends that are not "real" in any meaningful sense.

5. Proposed Alternative Marginal Cost Regressions

5.1 OVERVIEW OF ALTERNATIVE REGRESSION THEORY & METHODOLOGY

Q. What is your purpose in sponsoring alternative regression analyses and what exhibits are you sponsoring?

A. Based on my review of National Grid's regressions, as discussed in the prior section, I have determined that these regressions should be re-run consistent with best practices of econometric modeling. I am offering three proposed alternative regression analyses which assess marginal costs for distribution plant-related costs, distribution operations expenses, and distribution maintenance expenses. These regressions seek to correct for the deficiencies identified in the Company's exhibits.

[13] Spurious Correlation occurs when an analyst finds a relationship between *y* and *x* that is really due to other unobserved factors that affect *y* and also happen to be correlated with *x*. *See* Wooldbridge, at 50.

Q. What do you recommend?

A. Due to the deficiencies that I have identified in the Company's regressions, as described in Section 4, I recommend that the Department use the results of my proposed alternative regressions analyses to assess National Grid's marginal costs for distribution plant-related costs (Exh. AG-BWG-2 p1), distribution operations expenses (Exh. AG-BWG-3 p1), and distribution maintenance expenses. Exh. AG-BWG-3 p2. I also recommend that the Department use the results of Exhibit AG-BWG-4, which recalculates the total marginal costs based on my proposed alternatives for distribution plant-related costs, distribution operations expenses, and distribution maintenance expenses. Exhibit AG-BWG-4 also computes marginal capacity cost per Dth of delivery quantity, by rate class. The basis and reasoning for these proposed alternative exhibits are discussed below in Sections 5.2 (Alternative Regression for Distribution Plant-Related Costs), 5.3 (Alternative Regression for Distribution Operating Expenses), 5.4 (Alternative Regression for Distribution Maintenance Expenses), and 5.5 (Calculation of Marginal Costs).

Q. How are your workpapers structured?

A. I base my workpapers, Exhibits AG-BWG-2 through AG-BWG-4, on those developed by National Grid witness Bartos. My exhibits mirror those offered by witness Bartos, page for page, and rely on the same Company developed workbook. More specifically, Exhibit:

AG-BWG-2 p1 offers new regression results for distribution plant-related costs;

AG-BWG-3 p1 offers new regression results for operations expense;

AG-BWG-3 p2 offers new regression results for operations maintenance; and

AG-BWG-4 modifies Exhibit NG-MFB-6 only so far as to incorporate the sendout-related and demand-related costs identified in AG-BWG-2 and AG-BWG-3.

Because my review of other aspects of the MCS, aside from those detailed above, did not spur any criticism, I propose to maintain Exhibits NG-MFB-4 and NG-MFB-5 unchanged. Based on my marginal costs estimates, I update specific values in Exhibit NG-MFB-6 to match the marginal costs that I developed in Exhibits AG-BWG-2 and AG-BWG-3. To be clear, I did not make any changes to the formulas from Exhibit NG-MFB-6 when developing Exhibit AG-BWG-4, but instead merely inserted alternative marginal cost values into the existing workbooks to compute the resulting class-level marginal costs.

Q. What was your philosophy to developing marginal cost values?

A. My regressions are designed to be methodologically transparent, logically consistent, and simple to understand. They are also designed to conform with the same principles outlined by National Grid witness Bartos and Department precedent. All else equal, I prefer parsimony to specificity and am willing to accept lower goodness-of-fit if it provides better generality.[14]

[14] *See e.g.*, Wooldridge, at 201 (stating, "[e]verything else being equal, simpler models are better."); *supra* n.11.

Q. What was your methodological approach to developing marginal cost values?

A. I followed a simple method to generate regressions. This approach was used for all models developed. For each regression, I did the following:

1. Tested and corrected for autocorrelation based on an examination of the autocorrelation ("ACF") and partial autocorrelation ("PACF") values and graphs to identify the presence of autocorrelation with lags 1 through 8 (consistent with Exhibit NG-MFB-1 at 11, lines 9–11);
2. Added autoregressive term(s) to correct for any autocorrelation identified in Step 1 (consistent with Exhibit NG-MFB-1 at 11, line 12);
3. Added exogenous variables, using a consistent model specification, to the model. For each regression, the model specification posits that costs are a function of (a) demand, (b) sendout, and (c) the 2018 labor dispute. This approach is theoretically and practically distinct from the Company's non-structural approach. *See* Exh. NG-MFB-1 at 11, lines 6–8. If this simple regression model specification had weak explanatory power I would, instead, base my regression on the Company's exhibit, adding a sendout term, and stripping out unsupported variables.
4. Addressed multicollinearity if the following indicators of multicollinearity were present: high R squared values, but no coefficients that were statistically significant (consistent with Exhibit NG-MFB-1 at 11, lines 13–15);
5. Checked the reasonableness of results. For the model as a whole, this means that the predicted and observed values track reasonably well, that metrics of goodness-

of-fit suggest that a significant fraction of variability is explained by the regression, and that residuals were uncorrelated and normal. For individual coefficients within the regression, I assessed reasonableness by making sure that all values had the "right sign" and were statistically significant (p-value / t-statistic). This aligns with the Company's approach, as I understand it. *See* Exh. NG-MFB-1, at 11–12).

While this approach largely conforms with that of the Company, it has two major differences. First, it checks for auto-correlation *before* fitting the exogenous variables. Second, it keeps dummy and dummy-like variables to a minimum. This approach yields more parsimonious models which typically result in regressions with slightly lower explanatory power (as measured by the R^2 metric) but clearer and simpler coefficient interpretations.[15] This approach makes no efforts to enhance R^2 values because I consider the risk of over-fitting more important than increasing the share of variability accounted for with the explanatory variables. Given that there are only around 30-years of data (*i.e.*, 30 observations), overfitting risks are high.

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[15] My lower R^2 values are partly due to my preference for parsimony. An interesting fact about the R^2 metric is that when adding independent variable to an existing model, it never decreases and usually increases. Wooldridge, at 80–81; *see supra* n.11 and 14.

Q. With what statistical tools did you develop your regressions?

A. I developed my regressions using Python 3.8 and the Statsmodels library.[16] Statsmodels is an open-source tool for statistical analysis using Python. It includes, among other things, models for ordinary least squares ("OLS") regression and for ARIMA time-series regression.[17] Stastmodels is ubiquitous in scientific computing and according to Google Scholar, has been cited at least 1,345 times in academic literature.[18]

Q. Did you create an additional data series?

A. No. I relied exclusively on the data series generated by the Company. SPSS datafiles for reach regression were provided in response to AG-8-2.

5.2 ALTERNATIVE REGRESSION FOR DISTIBUTION PLANT-RELATED COSTS

Q. Please describe the data you relied on to model distribution plant-related costs?

A. I relied on the data provided by the Company in file "AG-8-2-1 Attachment CONFIDENTIAL.sav."

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[16] Seabold Skipper, and Josef Perktold. "Statsmodels: Econometric and Statistical Modeling with Python." *Proceedings of the 9th Python in Science Conference*, 2010, available at http://conference.scipy.org/proceedings/scipy2010/pdfs/seabold.pdf.

[17] Note that unlike OLS regression—which does not include any autoregressive processes—ARIMA models are non-linear and can only be fit using optimization techniques. Accordingly, different implementations of the same ARIMA model may yield slightly different coefficient results. For example, identical model specifications fit using Statsmodels and SPSS could generate somewhat different results—it is difficult to tell which one is "better" or "more accurate."

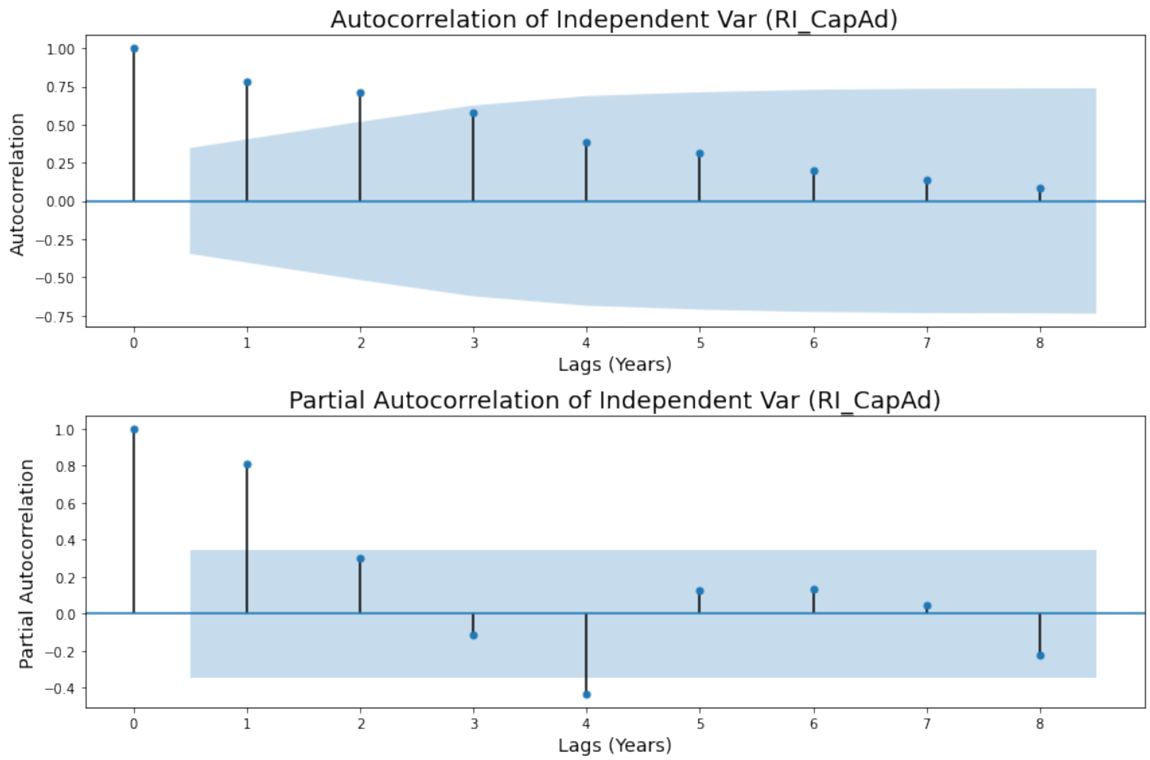
[18] https://scholar.google.com/scholar?cites=13768390100366339243

Q. Does the time-series for distribution plant-related costs ("RI_CapAd") exhibit autocorrelation? If so, how did you correct for it?

A. Yes, it does. Figure 1, depicting autocorrelation (ACF) and partial autocorrelation (PACF) plots for the distribution capacity additions costs variable ("RI_CapAd") demonstrate that there is significant autocorrelation for this variable, with a lag of one.[19] Because autocorrelation is apparent in the data, I added an AR(1) variable to the regression equation. Adding an AR(1) term makes the time-series stationery and accounts for all significant autocorrelation. Adding an AR(1) term also accounts for all higher order autoregressive processes. For whatever reason, the Company did not identify an AR(1) term but did include an AR(4) term. *See* Exh. NG-MFB-2. It is not clear how the Company settled on this specification.

[19] If an autoregressive process was not present, then autocorrelation would not gradually decline, as seen in Figure 1, but would be (a) of a smaller magnitude; and (b) randomly positive and negative from step to step, as seen in Figure 2.

Figure 1: ACF and PACF Plots for Variable RI_CapAd



Q. What variables do you include in your initial model?

A. Although I would have preferred to model total distribution plant costs against normalized peak demand, I was unable to do so due to data availability issues. Instead, like the Company, I treat distribution capacity additions costs ("RI_CapAd") as the regression's dependent variable. Initially, I developed a model which posited that operations expense was a function of (a) change in normalized peak demand ("Comb_Ch_Norm"), (b) total sendout ("Tot_send"), and a dummy variable for the year 2018.

Q. What are the results of this initial equation?

A. The initial model has an R^2 value of 0.58, meaning that 58% of observed variability in operations expense can be accounted for by the three explanatory variables. As noted above, the low explanatory power of my simple model is not unexpected given that it estimates the incremental increases to capital costs against incremental increases in demand, as opposed to estimating the total cost levels by year. Each coefficient has a high t-statistic and is statistically significant at the Company's preferred 10% level. Residuals are stationary and normal, indicating that the remaining error is all "noise." The coefficient for peak demand equals $3721.64/Dth-peak, indicating that a 1-Dth increase in peak demand would increase distribution capacity addition costs by $3721.64. The coefficient for sendout equals $0.7510/Dth, indicating that a 1-Dth increase in sendout would increase distribution capacity addition costs by $0.751.

By contrast, the Company model accounted for about 96% of observed variability. Given its low explanatory power, it appears that there is significant variability which is not accounted for. I concluded that the alterative model specification technique, eliminating low quality variables from the Company's specification in Exhibit NF-MFB-2, could improve model fit.

Q. What variables do you include in your final model?

A. To develop my final model for distribution plant-related additions, I started from the Company’s design in Exhibit NG-MFB-2. The Company’s model relates incremental plant additions to:

- 2-Year Lag Change in Normalized Peak Demand, for the years 2009–2019;
- Total Feet of Plastic Main on the System;
- Dummy variables for the periods 2009, 2013, 2018, and 2013–2019; and
- Autoregressive term of lag 4.

First, I added a sendout term (“Tot_Send”) to this base model and ran the regression. Considering the results, I found that all variables were significant and of the “right size”/ “right sign,” except for the plastic pipe term. The pipe term had a significance of 0.15, well above the Company’s 0.1 cutoff.

Second, consistent with Company’s methodology, I then removed the most insignificant term—plastic pipe—and re-ran the regression. In this updated regression, all values were significant and of the “right size”/“right sign” except for the AR(4) autoregression term. This term had significance of 0.3, well above the 0.1 cutoff.

Third, recalling that the ACF (Figure 1, above) plot exhibited signs of autocorrelation, lag 1, I updated the autoregressive term from AR(4) to the correct AR(1). The corrected model demonstrated that that AR(1) term was still not statistically significant.

Finally, thinking that the lag in the demand term (2 years) may be adversely interacting with the autoregressive term, I replaced the demand term with its non-lagged equivalent ("Comb_Ch_Norm"). Re-running this model, I found that all variables were significant and of the "right size" / "right sign."

Incidentally, this is the same model that would have been developed had I started with my base four-factor model, adding in the Company's dummy variables and controlling for years 2009, 2013, and the period 2013–2019. For whatever reason, these dummy variables can account for a significant amount of variability in observed plant additions.

Q. What are the results of this equation?

A. Exhibit AG-BWG-2 p1, presents the regression results that estimates the cost structure for distribution plant-related costs. In summary form, this model has an R^2 value of 0.93, meaning that 93% of observed variability in operations expense can be accounted for by the three explanatory variables. Each coefficient has a high t-statistic and is statistically significant at the Company's preferred 10% level. Residuals are stationary and normal, indicating that the remaining error is all "noise." The coefficient for peak demand equals $2186/Dth-peak, indicating that, all else equal, a 1-Dth increase in peak demand would increase capacity plant additions by $2186. The coefficient for sendout equals $0.47/Dth, indicating that, all else equal, a 1-Dth increase in sendout would increase capacity plant additions by $0.47.

Q. How do your results compare to those presented by the Company in Exhibit NG-MFB-2 p1?

A. As shown in Exhibit NG-MFB-2, the Company's model has an R^2 value of 0.96 (about 3% higher than my estimate) and finds that demand-related marginal costs equal $1177/Dth (about $1009/Dth *lower* than my estimate). The Company does not include any sendout-related term. Overall, this model had about the same goodness-of-fit as the Company's alternative (R^2 = 0.93 versus 0.96). I believe that my model is preferable to the Company's because my proposed model includes the logically relevant sendout term and corrects for the mis-specification of the auto-regressive term.

5.3 ALTERNATIVE REGRESSION FOR DISTIBUTION OPERATIONS EXPENSE

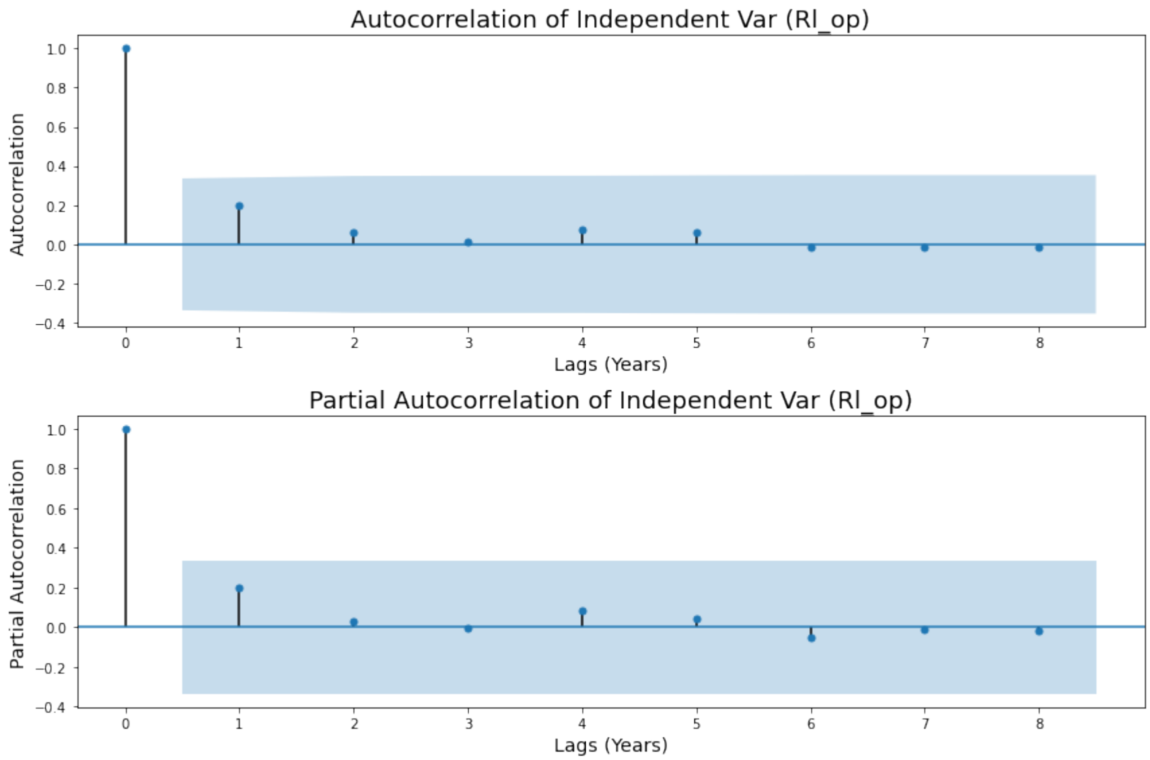
Q. Please describe the data you relied on to model distribution operations expense?

A. I relied on the data provided by the Company in file "AG-8-2-3 Attachment CONFIDENTIAL.sav."

Q. Does the time-series for distribution operations expense ("Rl-op") exhibit autocorrelation? If so, how did you correct for it?

A. No, it does not. Figure 2, depicting autocorrelation ACF and partial autocorrelation PACF plots for the distribution operations expense ("Rl_op") variable, demonstrate that there this no autocorrelation for the operations expense variable. The Company analysis agrees. *See* Att. AG-8-2-4 p3; Exh. NG-MFB-3 p1. Because autocorrelation is not apparent in the data, there is no need to correct for it.

Figure 2: ACF and PACF Plots for Variable Rl_op



Q. What variables do you include in your model?

A. Like the Company, I treat distribution operations expense ("Rl_op") as the regression's dependent variable. Initially, I developed a model which posited that operations expense was a function of (a) actual peak demand ("A_pk") and (b) total sendout ("Tot_send"). I also included dummy variables to control for costs in 2018 and 2019 (like the Company, to control for the labor dispute). The initial model suggested that all variables were significant. Unfortunately, the sendout coefficient was negative, violating the "right sign" criteria employed by both me and the Company. I developed a follow-up regression that omitted the sendout term but retained the actual demand term and the two dummy variables.

Q. What are the results of this equation?

A. Exhibit AG-BWG-3 p1, presents the regression results that estimates the cost structure for capacity-related distribution operations expense. In summary form, this model has an R^2 value of 0.98, meaning that 98% of observed variability in operations expense can be accounted for by the three explanatory variables. Each coefficient has a high t-statistic and is statistically significant at the Company's preferred 10% level. Residuals are stationary and normal, indicating that the remaining error is all "noise." The coefficient for actual peak demand equals $10.27/Dth-peak, indicating that, all else equal, a 1-Dth increase in peak demand would increase operations expense by $10.27. This model suggests that sendout has no significant effect on distribution operations expense, so should be treated as nil.

Q. How do your results compare to those presented by the Company in Exhibit NG-MFB-3 p1?

A. Results from both analyses are similar. As shown in Exhibit NG-MFB-3 p1, the Company's model has an R^2 value of 0.99 (about 1% higher than my estimate) and finds that demand-related marginal costs equal $13.2897/Dth (about $3/Dth *higher* than my estimate). I believe that my alternative proposed regression is preferable to the Company's value because my model is more parsimonious than the Company's (three variables compared with six, implying little explanatory power of the excluded variables) and has approximately the same overall explanatory power.

5.4 ALTERNATIVE REGRESSION FOR DISTIBUTION MAINTENANCE EXPENSE

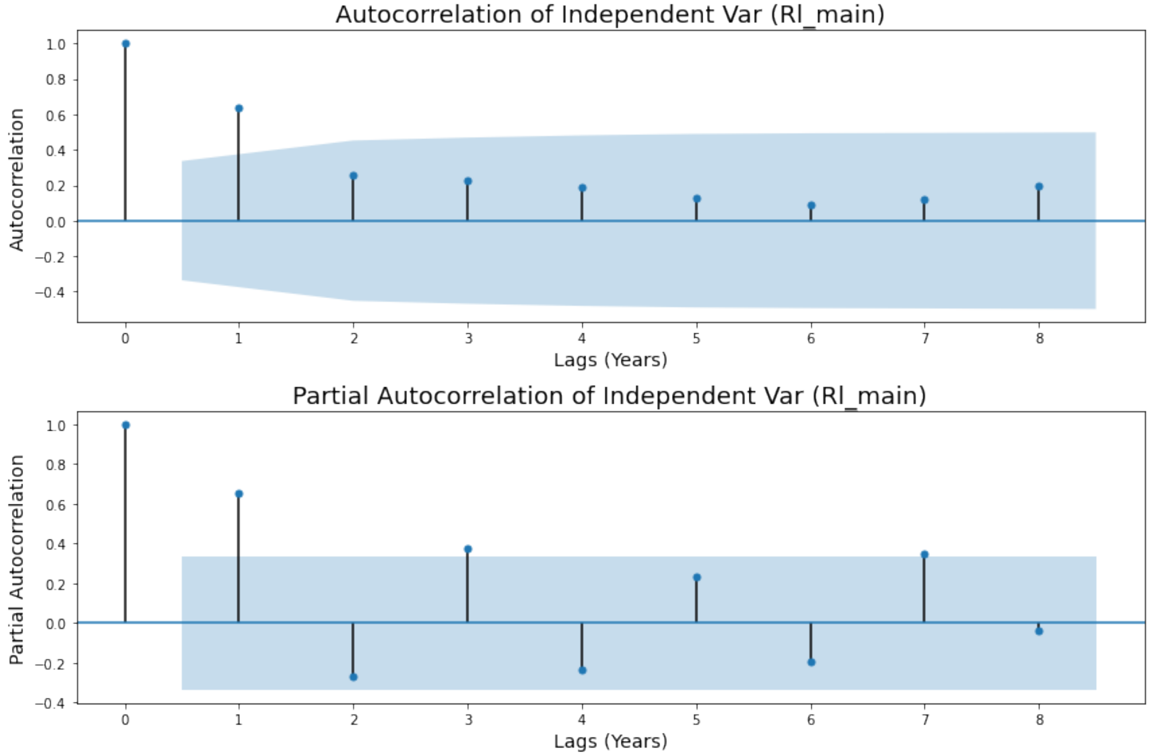
Q. Please describe the data you relied on to model distribution maintenance expense?

A. I relied on the data provided by the Company in file "AG-8-2-5 Attachment CONFIDENTIAL.sav."

Q. Does the time-series for distribution maintenance expense ("Rl-main") exhibit autocorrelation? If so, how did you correct for it?

A. Yes, it does. Figure 3, depicting autocorrelation ACF and partial autocorrelation PACF plots for the distribution maintenance expense ("Rl_main") variable demonstrates that there is autocorrelation for the operations maintenance variable, with a lag of one. Because autocorrelation is present in the data, I added an AR(1) variable to the regression equation. For whatever reason, the Company did not identify the need for an autoregressive term in its regression analysis. *See* Att. AG-8-2-6 p3; Exh. NG-MFB-3 p2.

Figure 3: ACF and PACF Plots for Variable Rl_main



Q. What variables do you include in your model?

A. Like the Company, I treat distribution maintenance expense ("Rl_main") as the regression's dependent variable. I developed a model which posited that operations expense was a function of (a) actual peak demand ("A_pk") and (b) total sendout ("Tot_send"). I also included dummy variables to control for the labor dispute costs in 2018 and 2019.

Q. What are the results of this equation?

A. Exhibit AG-BWG-3 p2 presents my regression results that estimate the cost structure for distribution maintenance expense. In summary form, this model has an R^2 value of 0.93, meaning that 93% of observed variability in operations expense can be accounted for by the four explanatory variables. Each coefficient has a high t-statistic and is statistically significant at the Company's preferred 10% level. The coefficient for actual peak demand equals $25.1345/Dth-peak, indicating that, all else equal, a 1 Dth increase in peak demand would increase maintenance expense by $25.1345. The coefficient for sendout equals $0.2316/Dth, indicating that, all else equal, a 1 Dth increase in send-out would increase maintenance expense by $0.23.

Q. How do your results compare to those presented by the Company in Exhibit NG-MFB-3 p1?

A. As shown in Exh. NG-MFB-3 p2, the Company's model has an R^2 value of 0.95 (about 2% higher than my estimate) and finds that demand-related marginal costs equal $19.5312/Dth (about $6/Dth *lower* than my estimate). The Company's model does not include a sendout-related term. I believe that my alternative regression is preferable to the Company's value because my model is much more parsimonious (four variables compared with seven), has about the same explanatory power, and captures relevant volumetric-related costs.

5.5 CALCULATION OF MARGINAL COSTS

Q. Can you please summarize your proposed alternative marginal costs?

A. Like the Company's Exhibit NG-MFB-6, Exhibit AG-BWG-4 presents the calculation of annual capacity-related distribution marginal costs (a) per Dth of demand, and (b) per Dth of annual sendout. Exhibit AG-BWG-4 summarizes and consolidates the estimated components of the Company's marginal cost of providing capacity-related distribution service that I presented in previous exhibits.

Exhibit AG-BWG-4 p2 shows the calculation of the Company's total loss-adjusted marginal costs to provide distribution service to each of the Company's major rate categories. I estimate that the annual loss-adjusted marginal distribution capacity-related cost of service at a customer's meter is $240.05 per Dth of Design Day Demand, and $0.2983 per Dth of delivery quantities. By contrast, the Company's estimated annual loss-adjusted marginal distribution capacity-related cost of service at a customer's meter is $148.47 per Dth of Design Day Demand, and $0.00 per Dth of delivery quantities. These marginal costs are converted to rate category-specific marginal cost rates per Dth of sendout on the same exhibit.

Q. Have you also developed the additional analyses of the Company's marginal costs that the Company can use to determine minimum rates for specific services?

A. Yes, incidentally. Because I rely on the MCS workbooks developed by the Company, my marginal cost values flow through to Exhibit AG-BWG-4 p3, which mirrors Exhibit NG-MFB-6 p3. I made no modifications to the Company's calculations beyond revising the values to be consistent with Exhibits AG-BWG-2 and AG-BWG-3.

Q. Have you developed unique marginal cost studies for Boston Gas and the former Colonial Gas?

A. No, not at this time. Given the simplicity of my approach, it should be easy for the Company to update its MCS to comport with best practices and develop simple, transparent, and consistent MCS regression values. That said, given the findings of National Grid witness Bartos about variation marginal cost values between National Grid, Boston Gas, and the former Colonial Gas (Exh. NG-MFB-1 at 3), it stands to reason that variability in costs between the different operating companies is likely to be modest.

6. Conclusion

Q. Does this conclude your direct testimony?

A. Yes.

Benjamin W.Griffiths

Updated March 2021

Summary of Professional Experience

Analyst, Massachusetts Attorney General's Office | Boston, MA (November 2018 – Present)
My primarily responsibility at the Massachusetts AGO is to provide qualitative and quantitative analysis of cases before the Department of Public Utilities ("Department"), as well as proposals before Independent System Operator ("ISO") New England and the Federal Energy Regulatory Commission ("FERC"). I evaluate and explain proposals, help formulate office positions, develop market enhancements, and offer testimony.

Independent Consultant | Austin, TX and Boston, MA (September 2017 – November 2018)
I developed policy insights and numerical models for projects related to distributed energy resources, energy efficiency, and retail rate design.

Research Analyst, Resource Insight Inc. | Arlington, MA (May 2012 – June 2015)
I analyzed electric utility resource planning, ratemaking, cost-of-service, and power procurement issues at an economic consultancy. I built, rebuilt, and reverse-engineered economic models, questioned underlying assumptions, implemented robust alternatives, and helped craft testimony on the results. I developed quantitative analyses on the economics and necessity of 16 power plants in seven states; suggested reasonable, least-cost alternatives. I modeled rate designs for encouraging efficient consumption in several states and Canadian provinces. I developed and ran electricity price forecasts for PJM and ISO-NE markets that integrated price data, ancillary services, load shapes, commodities forwards, and other factors.

Education

University of Texas at Austin, Jackson School of Geosciences | Austin TX
Master of Science, Energy & Earth Resources. Graduated: May 2017.

- Coursework: Decision Analysis, Systems Modeling, Probability, Mathematical Statistics, Energy Law, Electrochemical Materials, &c.
- Thesis: "Finding Carbon Breakeven: Induced Emissions from Economic Operation of Energy Storage in Renewables-Heavy Electricity Systems." Co-winner of the program's best thesis award.

Harvard University, Harvard Extension School, Cambridge MA | Boston MA
Non-degree coursework in Economics, Finance, & Statistics. Enrolled: January 2014 – May 2015.

Boston University, College of Arts and Sciences | Boston MA
Bachelor of Arts., magna cum laude, Classics and History. Graduated: January 2010.

Expert Testimony & Affidavits

3. **FERC [TBD]**: ISO-NE Cost of New Entry / Offer Review Trigger Price Update.
    - Affidavit of B.W.Griffiths in Support of the NEPOOL-Approved Proposal; Report on Market Revenues available to Energy Storage (On Behalf of the Mass AGO, Filed as part of the NEPOOL Comments, (Forthcoming).
2. **FERC ER20-1567**: ISO-NE Energy Security Improvements (ESI)
    - Affidavit of B.W.Griffiths in Support of the NEPOOL-Approved ESI Proposal (On Behalf of the Mass AGO, Filed as part of the NEPOOL Comments, April 15, 2020).
    - Answer of the Massachusetts Attorney General (June 16, 2020).
1. **FERC ER19-1428**: ISO-NE Inventoried Energy Program (IEP)
    - Testimony of B.W.Griffiths discussing why the inventoried energy program ("IEP") is unlikely to change the retirement decisions of market participants (On Behalf of the Mass AGO, March 25, 2019).

Publications (Articles, Whitepapers, Reports, &c.)

12. **B.W. Griffiths**, 2020, "Algorithmically Developing Efficient Time-of-Use Electricity Rates." Available at: https://papers.ssrn.com/abstract=3732850.

11. **B.W. Griffiths**, 2020, "Revenue for Energy Storage Participating in ISO-NE Energy and Reserves Markets: Alternative ORTP EAS Offset Estimates." Presented to NEPOOL Markets Committee. Available at: https://www.iso-ne.com/static-assets/documents/2020/11/a4_b_xii_ma_ago_memo_re_alternative_eas_energy_storage.pdf.

10. **B.W. Griffiths**, 2020, "Expensive, Ineffective, & Occasionally Counterproductive: Clean Peak Standards Simulation Results for New England" Available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3560193.

9. Mass AGO (M. Hoffer, R. Tepper, **B.W. Griffiths**, &c.) and Regulatory Assistance Project, 2020, "Wholesale Electric Market Design for a Low/No-Carbon Future: Report on the October 2019 Symposium & Proposed Next Steps". Available at: https://www.mass.gov/doc/wholesale-electric-market-design-for-a-lowno-carbon-future/.

8. **Griffiths, B.W.**, "Reducing emissions from consumer energy storage using retail rate design." *Energy Policy* (Volume 129, June 2019, Pages 481-490). Available at: https://www.sciencedirect.com/science/article/abs/pii/S0301421519300679.

7. Synapse Energy Economics (P. Knight, M. Chang, D. White, N. Peluso, F. Ackerman, J. Hall), Resource Insight (P. Chernick, **B.W. Griffiths**), etc. 2018. *Avoided Energy Supply*

Components in New England: 2018. Synapse Energy Economics and others for Avoided-Energy-Supply-Component (AESC) Study Group.

6. P. Chernick and **B.W. Griffiths**, October 26, 2018, "Review of NS Power Compliance Filing on its Proposed AMI Opt-Out Charge" Filed by the Nova Scotia Consumer Advocate in N.S. UARB Matter No. M08349.

5. **B.W. Griffiths**, 2017, "Finding Carbon Breakeven: Induced Emissions from Economic Operation of Energy Storage in Renewables-Heavy Electricity Systems." Available at: https://repositories.lib.utexas.edu/handle/2152/61660.

4. **B.W. Griffiths.,** C.W. King, G. Gülen, J.S. Dyer, D. Spence, and R. Baldick, "State Level Financial Support for Electricity Generation Technologies" White Paper UTEI/2018-1-1, 2018, available at: http://energy.utexas.edu/policy/fce.

3. **B.W. Griffiths**, G. Gülen, J.S. Dyer, D. Spence, and C.W. King, "Federal Financial Support for Electricity Generation Technologies" White Paper UTEI/2016-11-3, 2017, available at: http://energy.utexas.edu/the-full-cost-of-electricity-fce.

2. Hornby, R., P. Chernick, D. White, J. Rosenkranz, R. Denhardt, E. A. Stanton, J. Gifford, B. Grace, M. Chang, P. Luckow, T. Vitolo, P. Knight, **B.W. Griffiths**, B. Biewald. 2013. *Avoided Energy Supply Costs in New England: 2013 Report.* Synapse Energy Economics for Avoided-Energy-Supply-Component (AESC) Study Group.

1. P. Chernick and **B.W. Griffiths**, 2012, "Affordability of Pollution Control on the Apache Coal Units: Review of Arizona Electric Power Cooperative's Comments on Behalf of the Sierra Club." Filed as part of comments in Docket EPA-R09-OAR-2012-0021 by National Parks Conservation Association, Sierra Club, et al. Available at: https://www.regulations.gov/document?D=EPA-R09-OAR-2012-0021-0053

Presentations

5. B.W. Griffiths, 2020, "A (Gentle) Introduction to Wholesale Markets". Presented as part of the Mass AGO's Teach-in on ISO-NE, NEPOOL, and wholesale power markets on December 9, 2020.

4. B.W.Griffiths, 2020, "Value of Electric Vehicle Time-of-Use Retail Rates for Massachusetts Customers". Presented as part of the DPU Docket 20-69 Tech Sessions on December 3, 2020.

3. B.W.Griffiths, 2020, "Mass AGO Alternative Storage Energy & Ancillary Services Revenue Estimates for ORTP Reset", Successive Presentations to NEPOOL Markets Committee: September 8-10, 2020, October 6-8, 2020, and, November 9-10, 2020.
2. B.W.Griffiths and C.Belew, 2019-2020. "Amendments to the ISO-NE Energy Security Improvements Proposal" to (1) Elimination of the Replacement Energy Reserve; (2) Add a Lookback Provision. Successive Presentations to NEPOOL Markets Committee on September 3-4, 2019, January 14, 2020, February 14, 2020, March 11, 2020, and March 24, 2020.
1. London Economics International and the Mass AGO, 2019, "Chapter 3 Preliminary Proposal", Presentation to NEPOOL Markets Committee on March 6, 2019.

MA AGO (Based on Exhibit NG-MFB-2-GRID p1)

MARGINAL COST STUDY

Summary of Marginal Distribution Plant-Related Costs

Selected Model:

N.b., all values changed from the Company original are highlighted in yellow

1	Dependent Variable				
2	Total Annual Distribution Capacity Additions 2019$ (1988 - 2019)				
3	Explanatory Variables	Data base variable name	Coefficient value	t test	Significance
4	Constant	Constant	(32,890,000)	-2.81E+09	0
5	Dummy: Year 2009	D_2009	68,000,000	5.64E+11	0
6	Dummy: Year 2013	D_2013	(98,020,000)	-2.21E+11	0
7	Dummy: Year 2018	D_2018	(123,900,000)	-2.06E+13	0
8	Dummy: Years 2013 and After	D_2013_After	211,800,000	1.26E+10	0
9	Change in Normalized Peak Years	Comb_Ch_Norm	2,186	3.38	0.001
10	Total Sendout	Tot_send	0	4.65	0
11	Autoregressive Term: Lag 1	ar.L1	0	1.88	0.06
12	Model Statistics				
13	R_Squared	0.9305			
14	Adjusted R_Squared	Not Calculated			
15	Mean Absolute % Error (MAPE)	Not Calculated			
16	Passes ACF/PACF	Yes			

17

18 Marginal Cost Calculation

19 Distribution Plant Additions = -$ 32,890,000 + $ 68,000,000 x D_2009 + -$ 098,020,000 x D_2013 + -$ 123,900,000 x D_2018 + $ 211,800,000 x D_2013_After + $ 2186.07 x Comb_Ch_Norm + $ 0,000,000 x Tot_send + $ 0.29 x ar.L1

20

21 ∂ Distribution Plant / ∂ Peak Demand = $ 2,186 per Dth

22 ∂ Distribution Plant / ∂ Sendout = $ 0.466 per Dth

MA AGO (Based on Exhibit NG-MFB-3-GRID p1)
MARGINAL COST STUDY
Summary of Marginal Distribution Operations Expense

Selected Model:

N.b., all values changed from the Company original are highlighted in yellow

1	Dependent Variable					
2	Distribution Operations Expense 2019$ (1986 - 2019)					
3	Explanatory Variables		Data base variable name	Coefficient value	t test	Significance
4		Constant	Constant	9,368,000	2.12	0.0420
5		Actual Peak Demand	A_pk	10.27	2.26	0.0310
6		Dummy: Year 2018	d_2018	184,300,000	34.72	-
7		Dummy: Year 2019	d_2019	27,120,000	5.13	-
8						
9						
10						
11	Model Statistics					
12		R_Squared	0.9800			
13		Adjusted R_Squared	0.9780			
14		Mean Absolute % Error (MAPE)	Not Calculated			
15		Passes ACF/PACF	Yes			
16						
17	Marginal Cost Calculation					
18		Distribution Non-Customer Operations Expense = \$ 9,368,000 + \$ 10.27 x A_pk + \$ 184,300,000 x d_2018 + \$ 27,120,000 x d_2019				
19						
20		∂ Distribution Operations Expense / ∂ Peak Demand = \$ 10.27 per Dth				
21		∂ Distribution Plant / ∂ Sendout = \$ 0.000 per Dth				

MA AGO (Based on Exhibit NG-MFB-3-GRID p2)
MARGINAL COST STUDY
Summary of Marginal Distribution Maintenance Expense

Selected Model:

N.b., all values changed from the Company original are highlighted in yellow

Line		Data base variable name	Coefficient value	t test	Significance
1	Dependent Variable				
2	Distribution Maintenance Expense 2019$ (1986 - 2019)				
3	Explanatory Variables				
4	Constant	Constant	(21,150,000)	-5.66E+12	-
5	Dummy: Year 2018	d_2018	82,330,000	3.45E+13	-
6	Dummy: Year 2019	d_2019	73,070,000	3.67E+15	-
7	Actual Peak Demand	A_pk	25.13	1.82228	0.0680
8	Total Sendout	Tot_send	0.2316	2.353395	0.0190
9	Autoregressive Term: Lag 1	ar.L1	0.75	6.19752	-
10					
11					
12	Model Statistics				
13	R_Squared	0.9270			
14	Adjusted R_Squared	Not Calculated			
15	Mean Absolute % Error (MAPE)	Not Calculated			
16	Passes ACF/PACF	Yes			

17

18 Marginal Cost Calculation

19 Distribution Non-Customer Maintenance Expense = - $ 21,150,000 + $ 82330000.00 x d_2018 + $ 73,070,000 x d_2019 + $ 00,025 x A_pk + $ 0.2316 x Tot_send + $ 0,000,001 x ar.L1

20

21 ∂ Distribution Maintenance Expense / ∂ Peak Demand = $ 25.13 per Dth

22 ∂ Distribution Plant / ∂ Sendout = $ 0.232 per Dth

MA AGO (Based on Exhibit NG-MFB-6-GRID p1)
MARGINAL COST STUDY
Summary of Marginal Capacity Costs

N.b., all input values changed from the Company original are highlighted in yellow

Line			Source	Sendout	Source
1	Plant Investment				
2	Marginal Distribution Capacity Costs	$2,186.07	Exhibit AG-BWG-2, Page 1 Line 21	$0.4658	Exhibit AG-BWG-2, Page 1 Line 22
3	Marginal General Plant Loading Factor	2.43%	Exhibit NG-MFB-4, Page 3 Line 21	2.43%	Exhibit NG-MFB-4, Page 3 Line 21
4					
5	Total Marginal Plant Investment	$2,239.11	Line 2 * (1 + Line 3)	$0.4771	Line 2 * (1 + Line 3)
6					
7	Fixed Carrying Charge Rate	6.92%	Exhibit NG-MFB-5, Page 1 Line 20	6.92%	Exhibit NG-MFB-5, Page 1 Line 20
8					
9	Levelized, Annualized Cost of Marginal Plant Investment	$154.98	Line 5 x Line 7	$0.0330	Line 5 x Line 7
10					
11	Operations and Maintenance Expenses				
12	Marginal Operating Expense	$10.27	Exhibit AG-BWG-3, Page 1 Line 20	$0.0000	Exhibit AG-BWG-3, Page 1 Line 21
13	Marginal Maintenance Expense	$25.13	Exhibit AG-BWG-3, Page 2 Line 21	$0.2316	Exhibit AG-BWG-3, Page 2 Line 22
14					
15	Total Marginal O&M Expense	$35.41	Line 12 + Line 13	$0.2316	Line 12 + Line 13
16					
17	Administrative and General Expenses				
18	Marginal Plant related A&G per $ of Marginal Plant Investment	1.64%	Exhibit NG-MFB-4, Page 1 Line 21	1.64%	Exhibit NG-MFB-4, Page 1 Line 21
19	Plant related A&G Expense	$36.78	Line 18 x Line 5	$0.0078	Line 18 x Line 5
20					
21	Marginal Non-Plant related A&G per $ of Marginal O&M	5.03%	Exhibit NG-MFB-4, Page 1 Line 24	5.03%	Exhibit NG-MFB-4, Page 1 Line 24
22	Non-Plant related A&G Expense	$1.78	Line 21 x Line 15	$0.0117	Line 21 x Line 15
23					
24	Total A&G Expense	$38.57	Line 19 + Line 22	$0.0195	Line 19 + Line 22
25					
26	Marginal Working Capital Calculations				
27	Marginal M&S per $ of Marginal Plant Investment	0.79%	Exhibit NG-MFB-4, Page 2 Line 20	0.79%	Exhibit NG-MFB-4, Page 2 Line 20
28	M&S Cost	$17.76	Line 27 x Line 5	$0.0038	Line 27 x Line 5
29					
30	Cash Working Capital Allowance Rate	11.87%	43.31 Days	11.87%	43.31 Days
31	Working Cash O&M Allowance	$4.20	Line 30 x Line 15	$0.0275	Line 30 x Line 15
32	Revenue Requirement for Working Capital	$2.09	(Line 31 + Line 28) x Tax Effected Cost of Capital, Exhibit NG-MFB-5, Page 3 Line 21	$0.0030	(Line 31 + Line 28) x Tax Effected Cost of Capital, Exhibit NG-MFB-5, Page 3 Line 21
33					
34	Total Marginal Cost per Dth	$231.04	∑ Lines 9, 15, 24, 32	$0.2871	∑ Lines 9, 15, 24, 32
35	Escalator to Adjust to Rate Year	0.0390	Exhibit NG-MFB-5, page 3, Line 34	0.0390	Exhibit NG-MFB-5, page 3, Line 34
36	Total Adjusted Marginal cost per Dth	**$240.05**	Line 34 * (1 + Line 35)	**$0.2983**	Line 34 * (1 + Line 35)

MA AGO (Based on Exhibit NG-MFB-6-GRID p2)
MARGINAL COST STUDY
Calculation of Loss-Adjusted Marginal Costs
by Class

N.b., all input values changed from the Company original are highlighted in yellow

Line		Peak Demand	Sendout	
1	Lost and Unaccounted for			
2	Distribution	2.70%	2.70%	Company records
3				
4	Marginal Distribution Capacity Cost ($/Dth)	$240.05	$0.2983	Exhibit AG-BWG-4, Page 1 Line 36
5				
6	Loss-Adjusted Marginal Capacity Cost	$246.71	$0.3066	Line 4 /(1 - Line 2)

Line		R1/R2	R3/R4	G&T 41/42/43/44	G&T 51/52/53/54	
7						
8						
9	Normalized Usage - Annual Total (Dth)	1,387,315	70,691,370	42,276,860	20,179,114	Company records
10						
12	Normalized Peak Day Demand	10,692	801,149	509,483	136,261	Company records
13						
14	Marginal Capacity cost per Dth of Delivery Quantity	$2.21	$3.10	$3.28	$1.97	(Line 13 x Line 6 PeakDemand) / Line 9 + Line 6 Sendout
15						

MA AGO (Based on Exhibit NG-MFB-6-GRID p3)
MARGINAL COST STUDY
Summary of Marginal Capacity Cost Detail

N.b., all input values changed from the Company original are highlighted in yellow

Line		Peak Demand Total	Peak Demand Growth Expansion	Peak Demand Growth Core: Reinforce	Source
		(A)	(B)	(C)	
A1	Growth-related Allocation	100.00%	18.48%	81.52%	Company Provided
	Plant Investment				
A2	Marginal Distribution Capacity Costs	$2,186.07	$404.03	$1,782.04	Exhibit AG-BWG-4, Page 1 Line 2
A3	Marginal General Plant Loading Factor	2.43%	2.43%	2.43%	Exhibit NG-MFB-4, Page 3 Line 21
A4	Total Marginal Plant Investment	$2,239.11	$413.83	$1,825.28	(1+Line A3) x Line A2
A5	Fixed Carrying Charge Rate	6.92%	6.92%	6.92%	Exhibit NG-MFB-5, Page 1 Line 20
A6	Levelized, Annualized Cost of Marginal Plant Investment	$154.98	$28.64	$126.33	Line A5 x Line A4
	Operations and Maintenance Expenses				
A7	Marginal Operating Expense	$10.27	$1.90	$8.38	Exhibit AG-BWG-4, Page 1 Line 6
A8	Marginal Maintenance Expense	$25.13	$4.65	$20.49	Exhibit AG-BWG-4, Page 1 Line 7
A9	Total Marginal O&M Expense	$35.41	$6.54	$28.86	Line A7 + Line A8
	Administrative and General Expenses				
A10	Marginal Plant related A&G per $ of Marginal Plant Investment	1.64%	1.64%	1.64%	Exhibit NG-MFB-4, Page 1 Line 21
A11	Plant related A&G Expense	$36.78	$6.80	$29.99	Line A10 x Line A4
A12	Marginal Non-Plant related A&G per $ of Marginal O&M	5.03%	5.03%	5.03%	Exhibit NG-MFB-4, Page 1 Line 24
A13	Non-Plant related A&G Expense	$1.78	$0.33	$1.45	Line A12 x Line A9
A14	Total A&G Expense	$38.57	$7.13	$31.44	Line A13 + Line A11
	Marginal Working Capital Calculations				
A15	Marginal M&S per $ of Marginal Plant Investment	0.79%	0.79%	0.79%	Exhibit NG-MFB-4, Page 2 Line 20
A16	M&S Cost	$ 17.76	$ 3.28	$ 14.48	Line A15 x Line A4
A17	M&S Rev Req	$1.69	$0.31	$1.38	Line A16 x (Sched NG-MFB-5 p3 Line 21)
A18	Cash Working Capital Allowance Rate	11.87%	11.87%	11.87%	43.31 Days
A19	Working Cash O&M Allowance	$4.20	$0.78	$3.43	Line A18 x Line A9
A20	Working Cash Revenue Requirement	$0.40	$0.07	$0.33	Line A19 x (Sched NG-MFB-5 p3 Line 21)
	Marginal Cost-based Rate Calculations				
A21	Total Marginal Cost per Dth	$231.04	$42.70	$188.34	∑ Lines A6, A9, A14, A17, A20
A22	Escalator to Adjust to Rate Year	3.90%	3.90%	3.90%	Exhibit NG-MFB-6, Page 1 Line 35
A23	Total Marginal Cost per Dth, adjusted for Rate Year	$240.05	$44.37	$195.69	Line A21 * (1 + Line A22)
A24	Loss Factor	2.70%	2.70%	2.70%	Company Provided
A25	Total Marginal Cost per Dth, adj for Rate Year and losses	$246.71	$45.60	$201.12	Line A23 / (1 - Line A24)
A26	Plant-related Marginal Cost per Dth	$167.29	$30.92	$136.37	(∑ Lines A6, A17) * (1+Line A22) / (1 - Line A24)
A27	Expense-related Marginal cost per Dth	$79.42	$14.68	$64.74	(∑ Lines A9, A14, A20) * (1+Line A22) / (1 - Line A24)
A28	Contract Floor price (Capacity Constrained)	$246.71	$45.60	$201.12	Line A27 + Line A26
A29	Contract Floor Price (Capacity not Constrained)	$79.42	$14.68	$64.74	Line A27
	Rate per Dth for 100% Load Factor Customer				
A30	Contract Floor price per Dth (Capacity Constrained)	$0.9825	$0.1816	$0.8009	Line A28 / 365 + Line B28
A31	Contract Floor Price per Dth (Capacity not Constrained)	$0.4885	$0.0903	$0.3982	Line A29 / 365 + Line B29
	Rate per Dth for Average High Load Factor (G-50s) Customer				
A32	Contract Floor price per Dth (Capacity Constrained)	$1.9725	$0.3646	$1.6080	Line A28 x Sched NG-MFB-6 p2 Line 12/ Sched NG-MFB-6 p2 Line 9 + Line B28
A33	Contract Floor Price per Dth (Capacity not Constrained)	$0.8072	$0.1492	$0.6580	Line A29 x Sched NG-MFB-6 p2 Line 12/ Sched NG-MFB-6 p2 Line 9 + Line B29

Line		Sendout Total	Sendout Growth Expansion	Sendout Growth Core: Reinforce	Source
		(E)	(F)	(G)	
B1		100.00%	18.48%	81.52%	Company Provided
	Plant Investment				
B2		$0.4658	$0.0861	$0.3797	Exhibit AG-BWG-4, Page 1 Line 2
B3		2.43%	2.43%	2.43%	Exhibit NG-MFB-4, Page 3 Line 21
B4		$0.48	$0.0882	$0.3889	(1+Line B3) x Line B2
B5		6.92%	6.92%	6.92%	Exhibit NG-MFB-5, Page 1 Line 20
B6		$0.0330	$0.0061	$0.0269	Line B5 x Line B4
	Operations and Maintenance Expenses				
B7		$0.0000	$0.0000	$0.0000	Exhibit AG-BWG-4, Page 1 Line 6
B8		$0.2316	$0.0428	$0.1888	Exhibit AG-BWG-4, Page 1 Line 7
B9		$0.2316	$0.0428	$0.1888	Line B7 + Line B8
	Administrative and General Expenses				
B10		1.64%	1.64%	1.64%	Exhibit NG-MFB-4, Page 1 Line 21
B11		$0.01	$0.0014	$0.0064	Line B10 x Line B4
B12		5.03%	5.03%	5.03%	Exhibit NG-MFB-4, Page 1 Line 24
B13		$0.0117	$0.00	$0.01	Line B12 x Line B9
B14		$0.0195	$0.00	$0.02	Line B13 + Line B11
	Marginal Working Capital Calculations				
B15		0.79%	0.79%	0.79%	Exhibit NG-MFB-4, Page 2 Line 20
B16		$0.0038	$ 0.0007	$ 0.0031	Line B15 x Line B4
B17		$0.00	$0.00	$0.00	Line B16 x (Sched NG-MFB-5 p3 Line 21)
B18		11.87%	11.87%	11.87%	43.31 Days
B19		$0.0275	$0.0051	$0.0224	Line B18 x Line B9
B20		$0.0026	$0.0005	$0.0021	Line B19 x (Sched NG-MFB-5 p3 Line 21)
	Marginal Cost-based Rate Calculations				
B21		$0.2871	$0.0531	$0.2340	∑ Lines B6, B9, B14, B17, B20
B22		3.90%	3.90%	3.90%	Exhibit NG-MFB-6, Page 1 Line 35
B23		$0.2983	$0.0551	$0.2432	Line B21 * (1 + Line B22)
B24		2.70%	2.70%	2.70%	Company Provided
B25		$0.3066	$0.0567	$0.2499	Line B23 / (1 - Line B24)
B26		$0.0356	$0.0066	$0.0291	(∑ Lines B6, B17) * (1+Line B22) / (1 - Line B24)
B27		$0.2709	$0.0501	$0.2208	(∑ Lines B9, B14, B20) * (1+Line B22) / (1 - Line B24)
B28		$0.3066	$0.0567	$0.2499	Line B27 + Line B26
B29		$0.2709	$0.0501	$0.2208	Line B27

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Boston Gas Company d/b/a National Grid	))))	**DPU 20-120**

AFFIDAVIT OF BENJAMIN GRIFFITHS

Benjamin Griffiths does hereby depose and say as follows:

I, Benjamin Griffiths, on behalf of the Massachusetts Attorney General's Office, certify that the testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury this 23rd day of March, 2021.

Benjamin Griffiths