STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

In the matter of

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

Docket No. DG 20-105

Petition for Permanent Rate Increase

DIRECT TESTIMONY

OF

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<u>Introduction</u>

Q. Please state your name, occupation, and business address.

A. My name is Al-Azad Iqbal, and I am employed by the New Hampshire Office of the Consumer Advocate as Economics/Finance Director. My business address is 21 South Fruit Street, Suite 18, Concord, New Hampshire, 03301.

Q. Please summarize your educational and professional experience.

A. My educational and professional backgrounds are summarized in Appendix A.

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

A. The purpose of my testimony is to provide recommendations on issues related to the Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (Liberty, or the Company) rate proposal regarding 1) depreciation; 2) rate design, rate plan and; 3) other rate-related issues.

Q. Please summarize your recommendations on these issues.

A. I recommend that the depreciation reserve variance amortization, approved in the last rate case, be ceased until a new depreciation study is completed. The Company should follow the recommendations in the Review of Reserve Variance Deficiency for Liberty Depreciable Gas Plant done by Paul Normand and Marcy Stefan of Management Applications Consulting, Inc. (MAC); which is found at Testimony of Steven E. Mullen, Attachment SEM (Bates II 235-239) in Liberty's initial filing of July 31, 2020, in this docket. I recommend certain updates in the rate design process concerning the treatment of decoupling and low-income discounts. I also raise concerns about the Company's proposed capital budget, and the rate plan with step adjustments.

Depreciation

Q. What is the significance of depreciation for purposes of this proceeding?

A. As with all public utilities, EnergyNorth includes in its annual revenue requirement an amount that is, at least theoretically, equal to the decline in the value of the company's capital assets over a 12-month period. This is necessary because all capital assets decline in value over their period of usage. To account for that, the annual amount of depreciation is deducted from the utility's rate base (on which the utility receives a return on investment) and that same value becomes a recoverable operating cost. In this manner, the utility's shareholders receive both a return *on* their investment and, via depreciation charges, a return *of* their investment.

The accounting necessary to determine the amount recoverable from ratepayers as a depreciation expense is complicated. Utilities, including EnergyNorth, must constantly add new capital assets to their rate base. Meantime, operating conditions are not static and thus existing assets do not depreciate precisely as they were expected to at the time they first go into rate base. For this reason, a utility like EnergyNorth commissions a depreciation study from time to time, usually conducted by consultants who are expert in the field of depreciation. A depreciation study is a statistical exercise that takes into account the vintage of the utility's assets – that is, the year when each asset was placed into service – the pace at which specific assets are being retired from service, and actuarial principles that are helpful in updating determinations of how much useful life remains in the rate-based assets. The depreciation experts use statistical techniques to make mathematical calculations of how the forces of retirement are acting upon each plant category and an estimate of the service life remaining in each such category.

Q. When was the last depreciation study done for EnergyNorth?

A. EnergyNorth's last depreciation study was done in Docket DG 17-048, the company's most recent rate case before this one. In that docket, the company's depreciation consultant -- Management Applications Consulting (MAC) -- used a Simulated Plant Record (SPR) life analysis approach. The SPR approach is useful when a utility lacks sufficient records to develop actuarial data. In connection with this current docket, EnergyNorth again engaged Mr. Normand's firm. MAC did not conduct a complete depreciation study as it did for the previous rate case but, rather, reviewed the growth in the Company's plant with the goal of quantifying changes in the depreciation reserve imbalance (as required by the order issued in Docket DG 17-048 on April 27, 2018 (Order No. 26,122). The findings of Mr. Normand (along with his colleague, Marcy Stefan) are attached to Mr. Mullen's testimony as Attachment SEM 3.

Q. What is a "depreciation reserve imbalance"?

A. A utility's depreciation reserve is a fund the company accumulates annually, based on the probable replacement cost of its depreciable assets. The depreciation reserve – also referred to as accumulated depreciation – is equal to the total amount of depreciation charged against all of the utility's capital assets as stated on the utility's balance sheet. A depreciation reserve imbalance occurs when there is a difference between the depreciation reserve on the company's balance sheet (booked reserve) and the calculated value of the accumulated depreciation (theoretical reserve). When a comparatively large depreciation reserve imbalance exists, it is necessary to determine how to correct it. The imbalance can be amortized over a relatively short period of time or it can be spread over the entire future remaining life of the plant in service.

Q. Please describe the findings of Mr. Normand's and Ms. Stefan's review (as contained in Attachment SEM – 3).

A. The depreciation consultants stated that even with the amortization of the reserve variance approved in the prior rate case, the reserve variance increased significantly. The biggest contributors to this increase are Mains (accounts 367 and 376), and Services (account 380), which were the same accounts that caused the reserve variance in the depreciation study done in Docket 17-048. In the report found at Attachment SEM-3, MAC identified three items affecting the reserve variance that should be examined in the context of a new depreciation study: 1) potential change in average service life (ASL); 2) replacement/retirement of large quantities of mains and services; and 3) the cost of removal portion of the Company's plant replacement activities.

MAC posited that a new study would derive longer ASLs for both mains and services which would impact the resulting reserve variance. Further, MAC stated: "… large growth in plant investments which has been occurring for many years, especially for key plant accounts related to mains and services, results in large amounts of unrecovered dollars being identified but not recovered in the short term".[1] MAC further stated: "In the last ten years, the rapid increase in plant replacement/retirement requirements had, in many cases, resulted in a more detailed review of these costs (COR) which has resulted in being modified to reflect a much lower 3 to 5% range of costs to new plant investments."[2]

Based on its review, MAC recommended that Liberty do a detailed review of COR and undertake a new depreciation study. As I explain more fully later, COR is an important aspect of depreciation because, obviously, when the useful life of an asset has been fully exhausted it must be physically removed, which has a cost that is properly included in the calculation of depreciation costs.

Q. Is the recommendation for a detailed review of COR through a new depreciation study consistent with the goal of the depreciation study?

A. Yes. In the last depreciation study, MAC discussed the relevant issues in the context of the whole life depreciation system (*see* Docket No. DG 17-048, Attachment PMN-2, Bates page 431):

> The whole life accrual rate is a function of two variables: the estimated net salvage (salvage less cost to retire) and the average service life of the group. The continued use of accrual rates properly developed at one point in time as a function of all circumstances known and projected at that time can be assumed to be appropriate for a limited number of years; however, if the lives and net salvage are not re-estimated periodically, the rates may not provide the

1 *See* Attachment SEM-3, Bates page II-236.

2 *Id*.

> appropriate recovery of capital.

He also stated:

> Obviously, when a change in either net salvage or life expectations is observed, the book depreciation reserve compared to the computed or theoretical reserve immediately appears as either over or under accrued.
>
> …..
>
> In general, the variance in the reserve is simply the difference between theoretical reserve based on an updated set of factors as developed in a depreciation study and the existing book reserves which reflect the historical reserve adjustments previously approved. The theoretical reserve calculation, however, is based on a new set of accrual rates, and applying these results to the current plant balances as if they were constant historical factors will result in a variance.

He also explained:

> …statistical mortality studies of past retirement experience may provide historical indications of the dispersion of retirements and of average service life if there has been sufficient retirement activity over a reasonable period of time. Such information may provide some indication as to what to expect in the future; however, it should not be taken for granted that the future will mirror the past, especially when present policies, plans, or external circumstances indicate otherwise.

So Mr. Normand's recommendation is consistent with his overall approach to the depreciation study. The quotes I just provided also highlight the need to update the sets of factors as the data clearly indicates the current ASL, and CORs are not representing the characteristics of the company's assets.

Q. What is your opinion about the Average Service Life issue?

A. I agree with the consultant's analysis. Between 2007 and 2016, according to the two depreciation studies, Liberty's plant balance for Gas Mains increased by 70%, and for Gas Services by 74%. Further, since the last depreciation study in Docket DG 17-048, which was based on 2016 balances, these account plant balances have increased by 35% and 28%,[3] respectively in the test year. Effectively, the characteristics of these assets have changed significantly in recent years. Given these balances have essentially doubled in the past 15 years or so, and given that the more recent plant additions are supported by more reliable accounting data that is available for study, we concur with the consultants' recommendation that a new deprecation study based on 2020 data be performed in early 2021 to evaluate the impact on ASLs.[4]

Q. Please elaborate on the Cost of Removal issue.

A. On this issue, I agree with Mr. Normand's and Ms. Stefan's analysis in Attachment SEM 3. The current practice of applying a flat 10% (of plant investment) estimate for the cost of removal might not be reflecting the actual COR. MAC pointed out that in the last decade, more detailed reviews of COR have resulted in a much lower range (3% to 5%) for COR related to new plant investments. The COR is primarily labor costs. With industry improvements in automation, asset management technology, etc., the COR should be reduced over time. For example, GIS-based geocoding of the mains would make it possible to pinpoint the precise

[3] *See* Attachment SEM-3, Bates page II-235.

[4] In the last study, MAC identified data problem for both Mains, and Services accounts and stated: "Our analyses of this account were based on total assets since the Company could not provide any historical details by material type for analyses. … we note that the recording of retirements for the last two years has been backlogged." *See* Docket DG 17-048, Attachment PMN-2, at 35 and 37 (Bates pages 445 and 447).

location of an asset, which would reduce the need for unnecessary digging and corresponding labor costs. The century-old mains and services the Company is replacing now had very little documentation compared to today's accounting and documentation standards. As a result, the COR of new assets is expected to be more efficient, and applying the same blanket percentage (10%) to current investment costs would not be representative of those lower, future costs (when today's investments need to be removed).automation, asset management technology, etc., the COR should be reduced over time. For example, GIS-based geocoding of the mains would make it possible to pinpoint the precise location of an asset, which would reduce the need for unnecessary digging and corresponding labor costs. The century-old mains and services the Company is replacing now had very little documentation compared to today's accounting and documentation standards. As a result, the COR of new assets is expected to be more efficient, and applying the same blanket percentage (10%) to current investment costs would not be representative of those lower, future costs (when today's investments need to be removed).

Q. Please explain how the Cost of Removal impacts depreciation expenses.

A. The cost of removal is a component of the net salvage value. The net salvage component is an important factor in determining the annual accrual rate for each account. A COR represents the cost of disposing of an asset at the end of its life. For regulatory purposes, this cost is typically incorporated as a component of book depreciation. So a higher COR would require higher accrual rates and thus requires higher depreciation expenses.

Q. Please explain how the Cost of Removal impacts the reserve variance.

A. As previously mentioned, the reserve variance is the difference between theoretical reserves and existing book reserves. The theoretical reserve is based on an updated set of factors including COR. A change in COR would have a significant impact on the theoretical reserve, and thus on the variance. For example, if COR were reduced from 10% to 5% of the new investments as indicated in the review, it would reduce Net Salvage by approximately half.[5] If we adjust Net Salvage by half, the combined reserve variance from Mains and Services would change from a $16.3 million shortfall to a $4.5 million surplus. The same would have been true for the depreciation study from DG 17-048, and would have resulted in a surplus of $5.7 million rather than the shortfall of $9.9 million which is currently being amortized. When a reserve variance shortfall is amortized, the revenue requirement increases to the detriment of the ratepayers. When a reserve variance surplus is amortized, the revenue requirement decreases to the benefit of ratepayers.

Q. What is your recommendation?

A. It is obvious that the current set of factors (ASL and COR) need to be updated which will change the reserve variance significantly. So the amortization of the reserve variance which increases the revenue requirement by approximately $1.5 million is unnecessary and unreasonable. I support MAC's recommendations regarding a new depreciation study and

[5] For example, Mains net salvage would reduce to 7.5% from 15%.

recommend that the reserve amortization approved in the last rate case be discontinued in this case and any further amortization should be authorized only after the detailed COR and ASL evaluations MAC recommended are conducted, and/or a new depreciation study is completed. If this docket is completed before those studies are available, I recommend that the amortization be discontinued.

Q. Please explain the rationale of your recommendation.

A. As indicated by MAC, ASL and COR were the main factors cited in the last depreciation study as contributing to the reserve variance. Likewise, the current recommendation is to review the Mains and Services accounts. If ASL is increased and COR is reduced (as MAC's report at Attachment SEM-3, p. 2 suggest may be warranted), the reserve variance will be significantly reduced.

In the depreciation study in DG 17-048, Mr. Normand pointed out that the large swing in the reserve variance (from the prior study, which showed a reserve surplus) was the direct result of the very large, recent increases in investments in mains and services. The expectation in DG 17-048 was that this level of investments would continue to be exhibited in a similar fashion as has been experienced in the past.[6] In DG 17-048, Mr. Normand mentioned, establishing a "collar" or a threshold bandwidth for the variance, such that no amortization would occur unless

[6] *See* Attachment AMI-4; response to Staff 7-9(a) in DG 17-048: "The large deviation is a direct result of the very large plant dollar increases for these accounts (Mains $98M, Services $66M) driven primarily by the mandated replacement program (CIBS) which is expected to continue for some period of time. As a result, we expect that this behavior will continue to be exhibited in a similar fashion as has been experienced but at a lower level since the recent amortization from the last study will be terminated."

the variance was in excess of 5% -10% of the theoretical reserve level, as an option to minimize the swing.[7] The current reserve variance is below a 10% threshold, so no amortization would be done under that approach. In the last study, in Docket DG 17-048, the reserve balance was just above 6%. As indicated earlier, if ASL and COR are adjusted as a result of the reviews recommended in Attachment SEM-3, the variance would be lower and could be eliminated (i.e., in surplus).

In DG 17-048, the Commission approved a variance amortization at an accelerated rate of 6 years instead of 12 years approved in the case prior to DG 17-048. In addition, the Commission required that Liberty re-examine the reserve balance in its next case, as Mr. Normand and Ms. Stefan have done with the report submitted as Attachment SEM-3. Continuing to amortize the reserve variance at an accelerated rate as proposed by Liberty in this case without waiting for the results of the analyses recommended by the consultants in their report (Attachment SEM-3) is unreasonable, especially given Mr. Normand's and Ms. Stefan's suggestion that two specific areas (ASL and COR) are ripe for review and adjustment, and especially when a correction to these items could produce a variance that is much smaller (below 5%), and could potentially lead to a significant reduction in rates.

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[7] *See* Attachment AMI-4; response to Staff 7-9(c)(2) in DG 17-048. "If maintaining the WL [whole life] approach is required, then consider establishing a collar or a threshold band width for the variance such that no amortization would occur unless the variance is in excess of 5 or 10% of the theoretical level."

Rate Plan

Q. Please review some of the factors identified by the Company that led to the rate case filing in the current docket?

A. Mr. Mullen stated at Bates Page II-198 of his testimony that the major factor driving the Company's current rate request is the lag in recovery of capital investments and increases in costs, such as property taxes. He also mentioned the following factors - 1) decoupling; 2) reclassification of C&I customers; and 3) year-end customer count adjustment.

Q. Please address the decoupling issue cited by the Company.

A. The Company states that an increase in use (of gas) per customer (usage per customer, or UPC) impacts the Company negatively, but provides no support for this conclusion. Conceptually, UPC should have no impact on revenue under the approved decoupling mechanism. Decoupling sets the revenue per customer (RPC) based on test year data, not actual data. If the UPC changes from year to year, RPC should not. An increase in UPC might increase a customer's bill but would not impact the Company's revenue allowed under decoupling because any variances between allowed and actual revenue due to changes in UPC would be captured as over-or-under collections and would be reconciled through the Local Distribution Adjustment Clause (LDAC) Revenue Decoupling Adjustment Factor (RDAF) mechanism.

The concept of decoupling is based on the assumption that energy efficiency policies and programs reduce the sales of a utility's commodity – in this case, gas sales – and thus negatively affect the Company's earnings. Decoupling is designed to break this link between sales and revenues to eliminate any disincentive for utilities to implement EE programs based on the expectation that reductions in UPC result in associated reductions in revenue.

The reverse is also true – when UPC goes up, the revenue is not affected under decoupling. The Company's own review by its consultant (*see* Attachment AMI-1, OCA TS 1-7.3, Company Response to OCA DR TS 1-7) indicates that UPC does not impact the Company's revenue. Thus, I strongly disagree with the Company that decoupling warranted, or justifies, - the current rate case.

Q. Please address the rate class reclassification issue.

A. The Company claims that the reclassification of 1,598 commercial and industrial customers after the test year negatively impacted its revenue. The reclassification was the result of the Company's post-test year Rate Review process (Attachment AMI-2, Company Response to Staff DR 3-5.b). It is common practice for utilities to adjust customer rate classifications within a rate review process.

Q. What is your opinion on how the rate reclassification impacted the Company?

A. A rate classification adjustment could impact revenue, depending on the scale of migration from one class to another, because reclassification will determine the allowed revenue for those customers under decoupling. Usually, such migration patterns do not fluctuate significantly and impacts are negligible. If a customer migrates from a lower RPC class to a higher RPC class, the Company's allowed revenue would increase by the difference between the two RPCs and *vice versa*. According to the Company's analysis, the impact of reclassification is a reduction in allowed revenue under decoupling of $0.9 million. (Attachment AMI-2, Company Response to Staff DR 3-5.b).

The Company did not elaborate on the key reasons that could explain the somewhat large impact due to customer migration between rate classes. It matters how frequently the company reclassifies its customers. If the Company reclassifies its customers in a timely and diligent manner the impact due to reclassification cannot be substantive. The accuracy of the Company's test year revenues is important in any rate case filing. In this case, the Company claims a negative impact to its revenues, but in another situation the same factors might have a positive impact on its revenues.

Q. Please explain the end of the year adjustment issue?

A. Mr. Mullen described the end of year (EOY) adjustment issue as a methodology issue (Bates 11-199):

> The revenue adjustment was performed in a simplified manner, but the results of that adjustment were found to vary significantly from the determination of revenues to be received from customers under the Company's decoupling structure that uses monthly RPC amounts that vary by class. Due to the significant variations in monthly RPC amounts, the simplified methodology in the year-end customer count adjustment overstated the amount of revenue to be received from new customers.

I believe Liberty is concerned about the EOY adjustment methodology, which was proposed by Staff in DG 17-048 and was ultimately approved by the Commission. I believe that the simple methodology which was used in the last rate case (and in many other electric and gas rate cases and approved by the Commission) is reasonable. Usually, an EOY adjustment increases revenue and is applied to the test year sales number without any adjustment. In the rehearing process in DG 17-048, Staff identified the need for sales to be adjusted to ensure accurate rates. So while it is true that the application of the EOY adjustment to test year sales increase those sales for rate-setting purposes (which is consistent with using a year-end rate base in rate-setting) the same adjustment caused inflated rates in previous instances. This issue should be properly investigated where it is still used. In the current rate case, the EOY adjustment has been refined to address the data accuracy to a certain level. There might still be some room for improvement. OCA is open to improvements in the methodology, but supports the EOY adjustments as known and measurable adjustments that are consistent with using the year end rate base.

Rate Plan/Step Adjustments

Q. Why is the Company proposing multi-year step adjustments?

A. Mr. Mullen stated at Bates II-209 that "the largest negative impact on a utility's earnings between rate cases is the regulatory lag between the time capital investments are made and the time that recovery of the revenue requirement associated with those capital investments begins, particularly when those investments are considered non-revenue producing or non-growth related." He also pointed to the termination of the CIBS program and the need for an alternative method to obtain timely recovery of the costs involved with replacing leak-prone pipe on its distribution system.

Q. What is your opinion regarding non-revenue producing or non-growth related investment as a reason for multiple step adjustments?

A. Theoretically, investments that are not revenue producing or growth-related could be the basis for multiple step adjustments, but in this instance the planning and policy practices of Liberty undermine reliance on such investments as a reason for automatic rate increases outside of a rate case (when such planning and policy practices can be fully reviewed). Every utility faces regulatory lag. Customer growth provides an opportunity to minimize the impact of the regulatory lags, because customer growth produces increased revenue. Under decoupling, the revenue is stabilized for the Company but allowed to increase with customer growth. A reasonable utility would look for a balance between growth and non-growth capital investment so that the impact of regulatory lag would be manageable. Liberty's capital budget for the next five years (*see* Attachment AMI-3, Staff TS 3-9) shows an expansion in rate base from $346 million[8] at the end of 2019, plus a proposed $49 million[9] in actual investments in 2020, plus an *additional* $400 million in planned investments for 2021 through 2025, yet only 15% of its $400 million budget is growth-related and a lion's share of the non-growth, non-revenue-producing projects are discretionary. These amounts raise the question about Liberty's planning process, and management decisions – whether *doubling* the rate base in five years (while only 15% of that

[8] *See* Bates II-132R, line 1.

[9] *See* Staff TS 3-31.

investment is growth related) is a sound approach and beneficial for customers or in the public interest.

When this case was filed in July 2020, Liberty presented its "integrated capital spending plan" as Attachment BF/RM/HT-2, (Bates II-189) which showed projected spending as: 2021 at \$34.7M; 2022 at \$54.1M; and 2023 at \$53.4M. In Data Response OCA 3-8, Liberty stated that its capital budget was: 2021 - \$49M; 2022 -\$38M, and 2023 - \$59M. Then in February 2021, in Response Staff TS 3-9 (*see* Attachment AMI-3), the Company provided a revised capital budget for the next 5 years which showed the capital budget as follows: 2021 - \$48M; 2022 - \$111M; 2023 - \$74; 2024- \$93.5M; 2025 - \$75M. Without any explanation, Liberty's capital budget has practically doubled since this case was filed.

Based on the last CIBS filing (DG 20-049, Attachment CAM-1) the average CIBS investment was \$4.6 million per year. Since the last rate case, the average was \$10 million per year. The proposed step adjustment asked for a recovery of 80% of the non-growth capital investments which translates to an average \$54 million per year based on the latest capital budget described earlier. It is more than ten times the average CIBS investment. Even 20% of the non-growth capital investment (equivalent to \$13.5 million per year) is more than the average CIBS investment of the last few years.

The OCA fundamentally questions whether such enormous increases in rate base are necessary. Such large increases in capital will exacerbate any inherent regulatory lag, but the OCA questions whether such large budgets with a huge non-growth discretionary investment are appropriate for a rate plan involving a series of step increases as opposed to traditional rate review and recovery through test-year based rate setting.

Other Issues

Q. Do you have any observations regarding any inaccuracies or errors that might impact the Company's decision to file this rate case?

A. I will address several issues regarding the Company's decision to file this rate case. The first issue is related to the low-income discount program. The second issue is related to the Company's treatment of decoupling that impacted its rate request. As this is the first rate case filing that Liberty has made since implementing the decoupling mechanism, the Company, Staff and the OCA worked together to address these issues through a settlement agreement in the temporary rates phase of this proceeding approved by the Commission.

Q. Before discussing the issues, please explain how revenue requirement, revenue collected, and allowed revenues are different in a traditional rate filing as compared to a rate filing made after a decoupling mechanism has been implemented.

A. Traditionally, any increase of revenue requirement allowed is added to a company's test year revenue when setting the new rates. If a company had $1,000 in test year revenues and demonstrated a need to collect an additional $300, then the company would design base rates to collect $1,300. That is no longer true under decoupling. Decoupling involves two versions of revenue: a) the revenue actually collected at current rates, and b) the allowed revenue that the company can retain under decoupling. Decoupling creates a separation between the revenue actually collected and the allowed revenue. The difference that is either returned to or collected from customers is identified by the company as "decoupling revenue" which could be surplus or deficit in any given year. In traditional rate filings, there is no such separation between the revenue actually collected and the allowed revenue. Under decoupling, in a rate case, if current rates collected more revenue than the company was allowed, and there was no revenue deficiency due to other factors (such as plant increases or O&M increases), the rate case would reduce revenues though reduced rates. If there is an increase in revenue requirement, and it is equal to the "decoupling revenue," there would not be any change in rates (the base rate increase would be offset by the decoupling mechanism decrease). Only if the increase in revenue requirement is higher than the decoupling revenue would there be an overall rate increase.

Q. Can you now please elaborate on the two issues?

A. In its initial filings, the Company calculated its revenue increase based on its allowed revenue and applied the increase to the revenues collected at current rates. (*See* Petition Attachment 1, pp. 2-4.) This did not take into account that the current rates provide for a revenue collection above the allowed revenue. However, the request for an increase in revenue requirement must take into account *all* the revenues that are being collected under the current rates. The Company's filing had two mistakes: 1) the revenue amount under current rates did not reflect the revenues from the Residential Low Income Assistance Program (RLIAP),[10] and 2) the

[10] Currently known as the Gas Assistance Program (GAP).

Company translated an increase in revenue requirement directly to an increase in rates which incorrectly did not take into account that the current rates provide for a revenue collection above the allowed revenue, the difference that would have been returned to customers through the RDAF.

Q. Please explain the first issue.

A. The first issue is related to the low-income discount program. The Company collects low-income program discounts from all customers through the RLIAP as part of the LDAC. As a result, the Company's revenue is made whole when both the base rate and the LDAC collection of this discount are considered. However, in its initial rate filing in this case, the Company did not account for the low income discount revenue recouped through the RLIAP/ LDAC when calculating its required distribution revenue (revenue requirement).[11] Thus, to begin with, the Company missed approximately $2 million in revenue in its earning calculations, rate of return, revenue increase required, etc. Inexplicably, the Company made mistakes in the rate model which resulted in an additional increase in the revenue requirement by the same amount. These errors reflected a roughly $4 million impact.[12] Such a large figure might have influenced the Company's decision to file a rate case.[13]

[11] This created a bigger issue in the rate design model which is discussed later.

[12] The $4 million amount is significantly more than the $0.9 million adjustment due to customer reclassification, which was stated as one of the reasons for the rate case.

[13] This error was corrected in the February 21, 2021 by the Company through an updated report of proposed rate changes and updated attachments. *See* Tab 32.

Q. Do you have any recommendations to correct this issue in the future?

A. Yes. The source of these errors is the integration of low-income discounts in the rate design model. I recommend that the Company treat all low-income customers as regular customers for all rates and revenue related matters, and reconcile the discount through the LDAC. First, all electric utilities and the one other gas utility in the state follow this methodology for their low income program-discounts costs and rate design and have not made similar errors in revenue calculations. Secondly, with the changes implemented in the recent low income program docket (DG 20-013), the discount is no longer offered year-round; instead, it is offered only for the winter season, and the discount now also applies to the supply portion of the bill (whereas before it was limited to the distribution portion). This approach would eliminate the possibility of errors in the complexity of rate design modeling, and would make it be easier to address program costs through the LDAC.

Q. Are you proposing to eliminate Rates-4 or low-income rates?

A. No. I am proposing to change the way those rates are presented in the rate design process. For rate design, R-4 (low-income) customers would be recognized at regular customer rates, and the Company will count the regular rates as revenue for rate design purposes. The discount will be given to the customers and the recoupment of that discount from all other customers will be accomplished through the LDAC.

Q. Please explain the second issue.

A. The second issue is more nuanced and new under decoupling. If there is an over-collection above allowed revenue, the Company returns the excess revenue through its approved decoupling mechanism, the RDAF. In a decoupled environment, when there is a rate case the over-collection can be credited towards the required rate increase so that the revenue requirement is increased without changing the base distribution rates. As a result, the RDAF mechanism will be reset. So without increasing the distribution rates, the Company's revenue can be increased. This is accomplished by changing the revenue per customer (RPC). RPC calculations should be filed as part of the tariff compliance filing.

Q. Has this adjustment been done before?

A. Yes. That is what was done (at Staff's recommendation) in the temporary rate phase of this proceeding, *see* DG 20-105 Exhibits 5 and 6, where adjusted decoupling RPCs and usage per customer (UPC) were implemented. For the settlement agreement in the temporary rates phase the Company proposed and the Parties agreed to use current rates as temporary rates to provide a temporary allowed revenue increase. By increasing the allowed revenue in temporary rates by maintaining current rates, customers did not see an increase in rates but they also were no longer receiving the refund they would have received under the RDAF.

Q. Do you think the approach taken in the temporary rates settlement agreement regarding decoupling should be replicated in the future?

A. No. The OCA believes that the implementation of this method, which involved changing the usage per customer (UPC) during the temporary rates phase, is inappropriate. The UPC is part of what the rate case determines and it is premature to make that judgement at the temporary rate phase because, to analyze the UPC properly, stakeholders need more time than the temporary rate phase allows. In the future, rate increases at the temporary rate phase should only be accomplished through a change in the RPC as occurs during CIBS or a step increase.

Q. Please explain the rate design model issue you mentioned earlier.

A. As discussed earlier, in its Rates-5 rate design schedule the Company did not include the approximately $2 million in revenue that it collected through the LDAC. This oversight has two layers of impacts: 1) it inflates the required revenue increase, and 2) the revenue increase, applied to the deflated current revenue as the base, produces a higher percentage, which is then applied to the actual revenue when designing rates. For example, if the actual revenue is $100, and the low income program discount is $2, the Company is counting $98 for rate design and all other rate case filing purposes. If we assume that a cost of service study shows a required revenue of $105, then the rates model will show a revenue increase of $7 ($105 -$98) needed, as compared to the actual required increase of $5 (($105 -$100), with a difference of $2. This is the first layer. When the percentage increase is calculated, the model uses $98 as the base and $7 as the revenue increase, which is 7.14%. Then the Company applies this percentage to its actual current revenue of $100, giving them a revenue of $107.14, whereas it should be $105. In actuality, only a 5% increase was required.

In Docket DG 17-048, and in the initial filing in this case, the Company added another wrinkle in its Rates-5 schedule. Specifically, the Company added the low income program amount above the approved revenue increase. Continuing the example I have been using, assuming that the Commission approved the $7 revenue increase (incorrectly), the Company added another $2 to that revenue to recover the 'low-income program cost' so that the Rates-5 schedule would reflect a revenue increase of $9. Using the example previously given, the calculations will produce revenue of $109.2, instead of the $105.00 if everything were done correctly. Unfortunately, this mistake is what occurred in the last rate case DG 17-048 resulting in an increase in revenue currently reflected in the test year allowed revenue.

Q. Did the Company correct these issues in its updated filing?

A. Yes. Liberty updated its rate filing on February 25, 2021, which corrected how revenues under decoupling and the low-income discount program are accounted for when calculating revenue requirements, and designing rates, under a decoupling mechanism environment.

Q. Do you have any additional observation on the updated filing?

A. Yes. The updated filing requests an increase in delivery rates equivalent to $2.9 million by allocating $2 million to the production costs recovered in the Cost of Gas filings. In its original filing this $2 million was part of delivery rates. As our colleague Jerome Mierzwa has testified, the OCA agrees with this shift based on the functional cost of service study. This is still a proposed $4.9 million overall increase in rates.

The Company proposed revenue requirement increase, relative to the previously allowed revenue requirement, is actually $9.9 million which is the $4.9 million delivery and COG rate increases I just mentioned plus the of $4.97 million "decoupling revenue" increase implemented during the temporary rate phase.

Conclusion

Q. Please summarize your position?

A. In summary, OCA recommends the following:

- The OCA recommends that the amortization of reserve deficiency approved in the last rate case be discontinued until the ASL and COR are revised and a new depreciation study is done.
- On the rate plan issue, the OCA is concerned about the balance between growth and non-growth capital investment by the company, and recommends that any rate plan should incorporate a reasonable balance.
- The OCA recommends that the low-income rate class should be treated as regular residential customers in all rate design and revenue related purposes, and the low-income program cost should be dealt with in the cost of gas or any related dockets.
- The OCA recommends that in the future the UPC should not be changed during the temporary rate phase.
- The OCA recommends that the RPC calculations be filed as part of the tariff compliance filing.

Q. Does that conclude your testimony?

A. Yes.

Attachments

Appendix A

Educational and Professional Background

Al-Azad Iqbal

I am employed by the New Hampshire Office of the Consumer Advocate as the Economics/Finance Director. My business address is 21 S. Fruit Street, Suite 18, Concord New Hampshire, 03301.

I received my Bachelor degree in Architecture (B. Arch) from Bangladesh University of Engineering and Technology. Later, I received my Masters (MS) in Environmental Management from Asian Institute of Technology and another Masters in City and Regional Planning (MCRP) from the Ohio State University. I was a Doctoral Candidate at the City and Regional Planning Department at the Ohio State University. After joining the PUC in 2007, I participated in several utility related training courses including marginal cost training by National Economic Research Associates (NERA), Advanced Regulatory Studies through the Institute of Public Utilities at Michigan State University, and Depreciation Training with the Society of Depreciation Professionals. On March 12, 2021 I joined the Office of the Consumer Advocate as the Economics/Finance Director.

Prior to joining the PUC, I was involved in teaching and research activities in different academic and research organizations. Most of my research work was related to quantitative analysis of regional and environmental issues.

M E M O R A N D U M

TO:	**Peter Dawes**, Vice President, Finance and Administration Energy North Natural Gas ("ENNG" or the "Company") d/b/a Liberty Utilities
FROM:	**Gregg Therrien** Concentric Energy Advisors, Inc. ("Concentric" or "CEA")
CC:	**Steve Mullen** (ENNG), **James Bonner** (ENNG), **Chris Wall** (CEA), **Peter Hoegler** (CEA)
DATE:	August 8, 2019
RE:	**Review of ENNG's Revenue Decoupling Mechanism**

SECTION I. EXECUTIVE SUMMARY

ENNG has engaged Concentric to conduct an audit of its recently approved revenue decoupling mechanism ("RDM") because the actual RDM results to date have resulted in distribution revenues $1.4 million[1] below that allowed in the Company's last rate case.[2] Additionally, the RDM calculation has shown volatile results and has produced an unanticipated large credit to customers over the first seven months since the RDM has been in place.

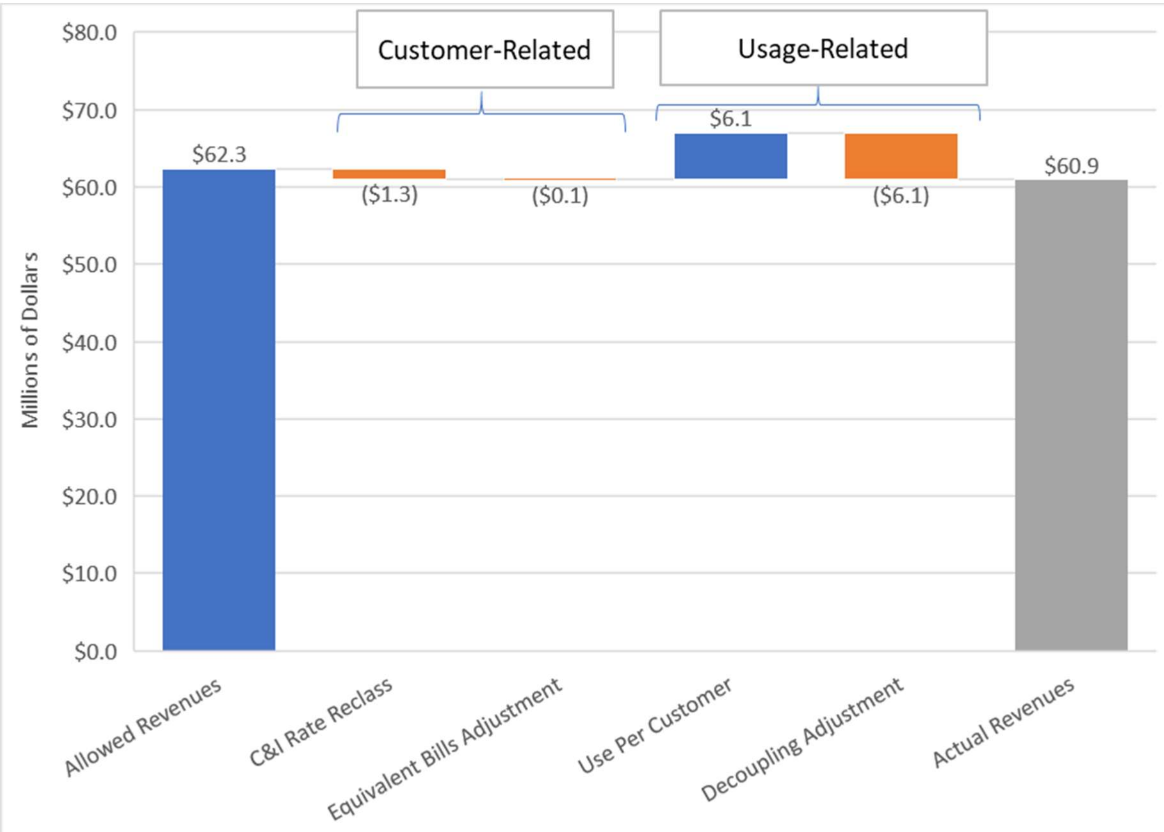
Concentric's findings are summarized as follows:

i. *The Company's RDM calculations are accurate.*
ii. *Actual class-level customer counts are significantly different than approved customer levels, resulting in a $1.4 million distribution revenue shortfall because:*
    a. *A Post-Test Year C&I customer reclass was not reflected in the rate case, and*
    b. *The New Hampshire Public Utilities Commission ("NHPUC") Staff made an "equivalent bills" adjustment in the rate case that makes attaining allowed revenues difficult.*
iii. *Increased use per customer is driving the large RDM credit.*
iv. *ENNG's use per customer trends are consistent with other regional natural gas companies.*
v. *The real-time weather normalization adjustment ("WNA") is now functioning properly after a $0.264 million error was discovered in November 2018 and subsequently credited back to customers in April 2019.*
vi. *The Company's unbilled revenue methodology is prone to higher monthly variation than other methods. Two minor errors in the seven months of entries also contributed to monthly decoupling entry variances.*

[1] For the period of November 2018 through May 2019.
[2] Docket No. 17-048 "Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities Distribution Service Rate Case", Final Decision dated April 27, 2018 (the "Final Decision").

The following chart summarizes the components of the variance between allowed and actual distribution revenues:

Chart 1: Components of Distribution Revenue Variance



The purpose of an RDM is to sever the link between sales units (usage) and revenues, thus enabling companies to freely promote conservation measures to their customers without suffering financial harm. A revenue per customer ("RPC") RDM construct is intended to recognize that adding new customers requires compensation to fund the incremental investment necessary to connect that customer to the distribution system. As such, an RPC RDM does not reconcile differences in customer counts.

The above chart shows that changes in customers compared to the approved rate year has resulted in an unfavorable margin variance of $1.4 million. This is primarily the result of two factors: 1) a February 2018 commercial and industrial ("C&I") rate review, which resulted in a significant reclassification of customers among the C&I rate schedules, and 2) a late adjustment to target (allowed) distribution revenues and customer counts ("equivalent bills") by the NHPUC Staff at the end of the rate case proceeding.

The $6.1 million favorable margin variance related to higher use per customer is properly captured through the RDM and nets to zero.

SECTION II. BACKGROUND

ENNG has engaged Concentric to conduct an audit of its recently approved RDM because the actual RDM results to date have resulted in distribution revenues $1.4 million below that allowed in the Company's last rate case. Additionally, the RDM calculation has shown volatile results and has produced an unanticipated large credit to customers over the first seven months since the RDM has been in place. The large RDM credit is unanticipated because the "real time" WNA is billed monthly on each customer's bill, thereby eliminating the largest anticipated variance component of the RDM, weather. Concentric first produced a work plan to address the primary purpose of this engagement, which is to determine whether there are any structural deficiencies in the RDM construct.

The details of this work plan consist of the following:

1. *Verify that the RDM is functioning properly, through investigation of the following:*
    - i. *That the Allowed Revenue Per Customer being used in the RDM calculation is accurate and consistent with the approved billing determinants and allowed revenues from the rate case;*
    - ii. *That the Actual Revenue Per Customer ("RPC") since inception of the RDM is also calculated correctly, and*
    - iii. *That Concentric's independently calculated monthly RDM variances are equal to that recorded by the Company.*
2. *Quantify the monthly variances by category (i.e., customer-related and usage related);*
3. *Calculate the monthly weather-related variance and compare that result to actual billed WNA revenues;*
4. *Validate the monthly unbilled entries, and quantify the unbilled contribution to monthly variances, and*
5. *Summarize our audit findings and provide Concentric's recommendations.*

SECTION III. THE ENNG VARIANCE ANALYSIS

The Company provided Concentric with its monthly decoupling values as well as its variances to allowed distribution revenues. This is summarized as follows:

Table 1: Variance to Allowed Distribution Revenues (November 2018 – May 2019)

Line	Revenue Type	Total
1	Allowed Distribution Revenues	62,292,497
2	Actual Distribution Revenues	60,930,806
3	Difference	(1,361,691)
4	Decoupling Deferral[1]	(6,089,952)

1 Included in Line 2 above.

As Table 1 indicates, cumulative actual revenues (inclusive of the decoupling adjustment) are below allowed by $1.4 million. This significant unfavorable variance, coupled with the larger than anticipated decoupling adjustment, led to this audit to ensure the RDM is functioning properly and that the base revenue target RPC is appropriate and calculated consistent with the Final Decision.

SECTION IV. PRELIMINARY RESULTS

On July 12, 2019 Concentric reviewed a Microsoft PowerPoint© presentation with ENNG Management. This presentation included the following preliminary findings:

- The Company's RDM calculations are accurate.
  - Target RPC, by class and in total, are calculated correctly;
  - Actual Calendar Revenues cannot be calculated on a Class RPC basis because of the system-wide unbilled methodology, and
  - The method used to calculate the decoupling adjustment is different than the approved tariff methodology, but mathematically should yield the same result.
- Actual customer counts are below Allowed levels, primarily in the Commercial and Industrial ("C&I") rate classes result in a $0.7 million[3] delivery revenue shortfall that is not recoverable through decoupling.
- Use Per Customer Growth drives the higher than anticipated decoupling credits.
- The unbilled calculation contributes significantly to the monthly variances, making it difficult to assess the true impact of the decoupling adjustment.

As a result of this presentation Concentric was asked to further investigate use per customer trends from other New England gas companies. The above findings have been validated and refined, and now also include the requested use per customer comparisons.

SECTION V. FINAL FINDINGS

A. The Company's RDM calculations are accurate.

Concentric validated the Company's monthly RDM calculations by performing three tests:

1. *Replicate the monthly Target RPC;*
2. *Validate the Company's monthly Actual RPC, and*
3. *Compare the differences from steps 1 and 2 to the Company's reported monthly decoupling amounts.*

These steps require a review of the Company's unbilled methodology and monthly entries, which are necessary to report monthly revenues on a calendar basis.

The first audit test was to validate that the monthly RPC targets were calculated correctly using class-specific data from the Final Decision. CEA first obtained the final approved billing determinants from the Final Decision, which includes the number of customers (equivalent bills), throughput (therms), and the appropriate tariff's monthly fixed charges and delivery rates per therm. We then multiplied these billing determinants by the tariff rates to derive monthly allowed distribution revenues by rate class. Each class-specific distribution revenue was then divided by the allowed number of equivalent bills to derive class-

[3] Concentric's preliminary finding used customer rates to quantify the customer variance. The final analysis contained in this memorandum properly uses the class RPC values, which are used in the RDM calculation.

specific revenue per customer targets. Lastly, these revenue per customer targets were compared to the Company's RDM calculation workbook and were found to tie out in each class for each month.

The second step was to validate the Company's Actual RPC calculations. This was performed in total rather than at the class level because of the nature of the unbilled calculation (discussed below in Section VII). Unbilled is calculated by first using actual system gate station receipts less company use, daily metered volumes[4] and a lost-and-unaccounted-for deduction[5] pertaining to local delivery system losses. Because the Company utilizes the "gate station approach" to estimate unbilled sales, class-level detail is not possible. Therefore, Concentric reviewed both the class-specific billed revenues, the unbilled revenue estimate and the calculation of monthly equivalent bills to validate the monthly Actual revenues.

Concentric's review of the underlying billing data and unbilled entries did uncover a minor unbilled estimation error whereby the number of equivalent bills used in the unbilled calculation were incorrect for the months of November 2018 through and including March 2019[6]. This error has no effect on the seven-month cumulative variance, as the unbilled accruals are reversed each month and the equivalent bills error was corrected in the April 2019 accrual. Concentric then performed a second reasonableness test whereby the unbilled sales volumes and equivalent bills were spread to the rate classes based on billed volume percentages. This provided a "sanity check" calculation, which showed material volatility in the C&I classes. The root cause of this volatility is discussed below.

The third step compares the actual RPC to the Allowed RPC and multiplied times the number of calendar month equivalent bills. This calculation yielded a decoupling value very close to the Company's recorded decoupling revenues in total, but significant monthly variances in the months of November 2018 through March 2019.

A. Customer counts are significantly different than that allowed in the rate case.

Average customers for the period of November 2018 through May 2018 were compared to the 2016 rate year for each rate class. The variance in customer counts was then multiplied times the Allowed RPC for the same period. This calculation is shown below:

[4] Daily metered volumes are excluded from the unbilled calculation as they are billed on a true calendar basis.

[5] The Company utilizes a 1.6% lost-and-unaccounted-for percentage in all months. No attempts were made by Concentric to validate this assumption.

[6] Actual cycle-based number of bills was inadvertently used in these five months.

Table 2: Distribution Revenue Impact Related to Average Customer Counts

	Average Customer Counts			Distribution Revenue	
Rate Class	**Actual**	**Rate Year**	**Actual Versus Rate Year**	**Allowed RPC 11/2018 through 5/2019**	**Rate Year Variance**
R-1	3,133	3,558	(425)	$167	($70,804)
R-3	72,472	72,142	330	$458	$151,279
R-4	5,906	5,315	592	$177	$104,676
R-5	64	-	64	$217	$13,882
R-6	185	-	185	$596	$110,225
R-7	3	-	3	$230	$707
Total Residential	**81,763**	**81,015**	**749**		**$309,964**
G-41	9,200	9,147	53	$1,117	$58,864
G-42	1,379	1,755	(376)	$6,515	($2,448,421)
G-43	58	48	10	$43,278	$432,051
G-44	2	-	2	$1,452	$2,317
G-45	4	-	4	$8,469	$36,216
G-46	-	-	-	$56,262	$0
G-51	1,227	1,360	(133)	$810	($107,489)
G-52	374	325	49	$4,085	$199,787
G-53	36	32	4	$34,929	$151,109
G-54	28	26	2	$25,621	$52,094
G-55	3	-	3	$1,053	$2,909
G-56	-	-	-	$5,311	$0
G-57	-	-	-	$45,408	$0
G-58	1	-	1	$33,307	$36,320
Total C&I	**3,109**	**3,546**	**(437)**		**($1,682,336)**
Total All	**84,872**	**84,561**	**311**		**($1,372,372)**

As the above table indicates, the total difference in customer counts is the source of the difference between Actual and Allowed distribution revenues.

a. A Post-Test Year C&I Customer Reclass was not Included in the Decoupling Targets.

In February 2018 the Company analyzed its C&I rate classes to determine if any customers were not properly assigned to the appropriate rate class. For example, if a commercial customer has been receiving service under Rate G-41 (with an availability requirement that the customer must use less than 10,000 therms annually and use more than 67% of its annual usage in the winter months) and, as a result of the annual rate review it is determined that the customer has increased its annual usage above 10,000 therms, the customer is then reclassified to the G-42 rate schedule.

Concentric's review of current customer counts compared to that imputed into allowed revenues showed significant variation, particularly in the C&I class. We determined that the C&I rate review conducted in February 2017 was not accounted for in the rate case. The summary of these customer reclasses is as follows:

Table 3: February 2017 C&I Rate Reclassifications

Rate Class	C&I Customer Reclass				
	Out	In	Net	11/2018 - 5/2019 Allowed RPC	Delivery Revenue Impact
G-41	(489)	789	300	$1,117	$335,148
G-42	(529)	241	(288)	$6,515	($1,876,269)
G-43	(18)	17	(1)	$43,278	($43,278)
G-51	(437)	358	(79)	$810	($64,015)
G-52	(97)	162	65	$4,085	$265,532
G-53	(10)	15	5	$34,929	$174,647
G-54	(9)	7	(2)	$25,621	($51,241)
Total	**(1,589)**	**1,589**	**-**		**($1,259,476)**

This variance is a subset of the total customer-related margin variance calculated in Table 2.

b. Test Year Adjustments Included in the Decoupling Targets Makes Attaining Imputed Customer Counts Difficult.

Near the completion of the litigated rate case in Docket No. 17-048 the Commission Staff required the Company to make a calendarization adjustment for the number of test year bills. This adjustment is intended to "normalize" the test year customer counts and reflect new customer accounts added during the test year. The Company's approach to this request was to calculate an equivalent bills adjustment, which both smoothed test year customer counts and recognized new customer additions made during the test year. This adjustment resulted in the following increase to Allowed customer counts, therms and revenues:

Table 4: Rate Year Equivalent Bills Adjustment

Rate Class	Annual Bills	Annual Therms	Delivery Revenues
R-1	386	7,154	$8,475
R-3	14,336	1,043,363	$789,374
R-4	(1,580)	(214,472)	($56,689)
Total Residential	**13,142**	**836,045**	**$741,160**
G-41	3,214	485,913	$342,087
G-42	343	561,680	$238,682
G-43	(28)	(554,018)	($138,357)
G-51	99	14,201	$8,535
G-52	79	155,599	$40,388
G-53	(21)	(544,071)	($96,774)
G-54	(16)	(836,835)	($47,439)
Total C/I	**3,670**	**(717,529)**	**$347,123**
Total All	**16,812**	**118,516**	**$1,088,283**

The above adjustment is included in the Approved RPC targets resulting in a higher customer count that must be attained to achieve allowed delivery revenues. The RDM adjustment does not compensate the Company for lower actual customer counts than that imputed into base delivery revenues. The RDM is designed to sever the link between sales (therms) and revenues, not customer counts.

B. Use Per Customer

Again, the purpose of the RDM is to sever the link between customer usage and delivery revenues. Reasons for usage variances are primarily the result of colder or warmer than normal weather, conservation measures (from both ratepayer-funded programs and individual customer conservation measures) and economic activity. Given the Company's RDM construct that includes a real-time WNA, the variances related to use per customer were anticipated to be small. To the contrary, the decoupling revenue adjustment has credited customers $6.1 million over the first seven months of operation. The real-time WNA has properly captured the weather-related variance (discussed in Section VI below), which leaves the entire RDM adjustment attributable to use per customer. The increase in use per customer has occurred in both the Residential and C&I sectors:

Chart 2: Residential Use Per Customer

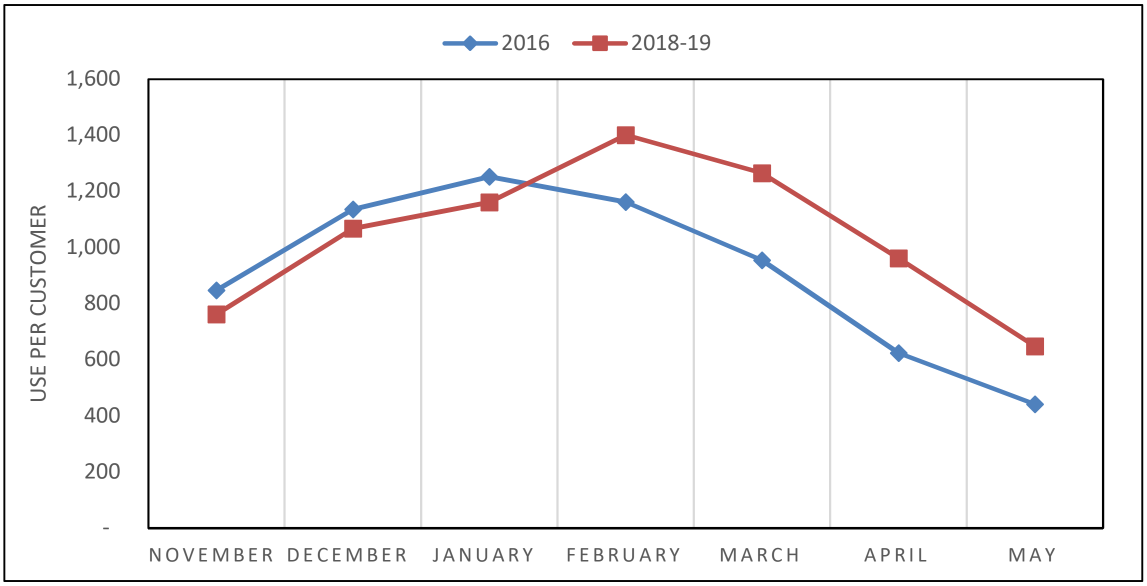
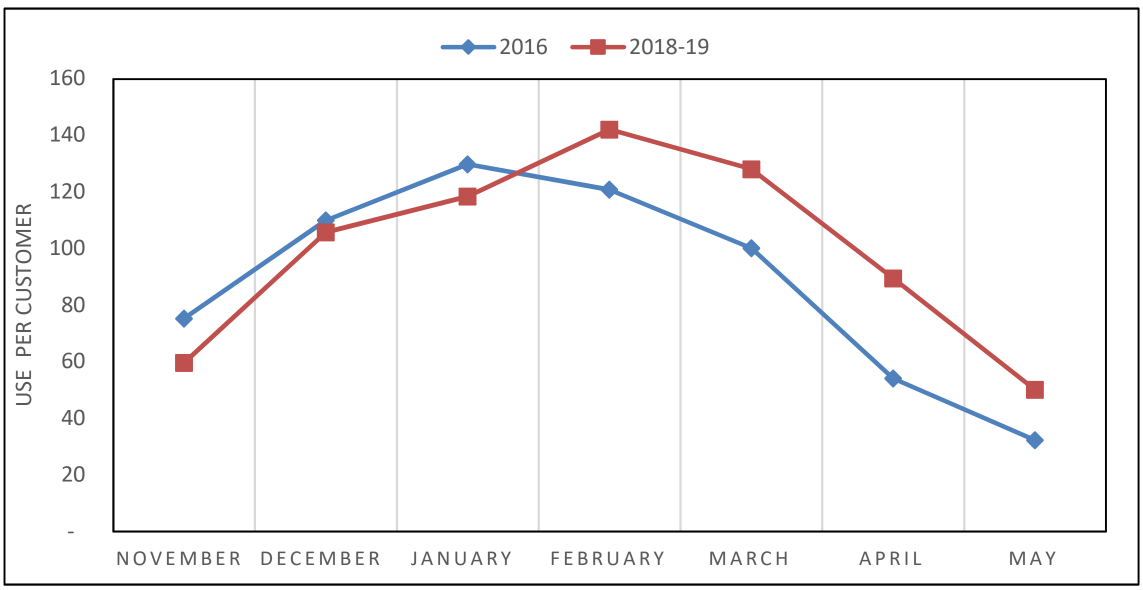


Chart 3: C&I Use Per Customer



At the preliminary findings presentation, the Company was surprised by the recent increase in UPC, particularly for the Residential class. Concentric was asked to compare ENNG's UPC to that of neighboring natural gas utilities. Concentric was able to obtain customer and usage data from the following companies[7]:

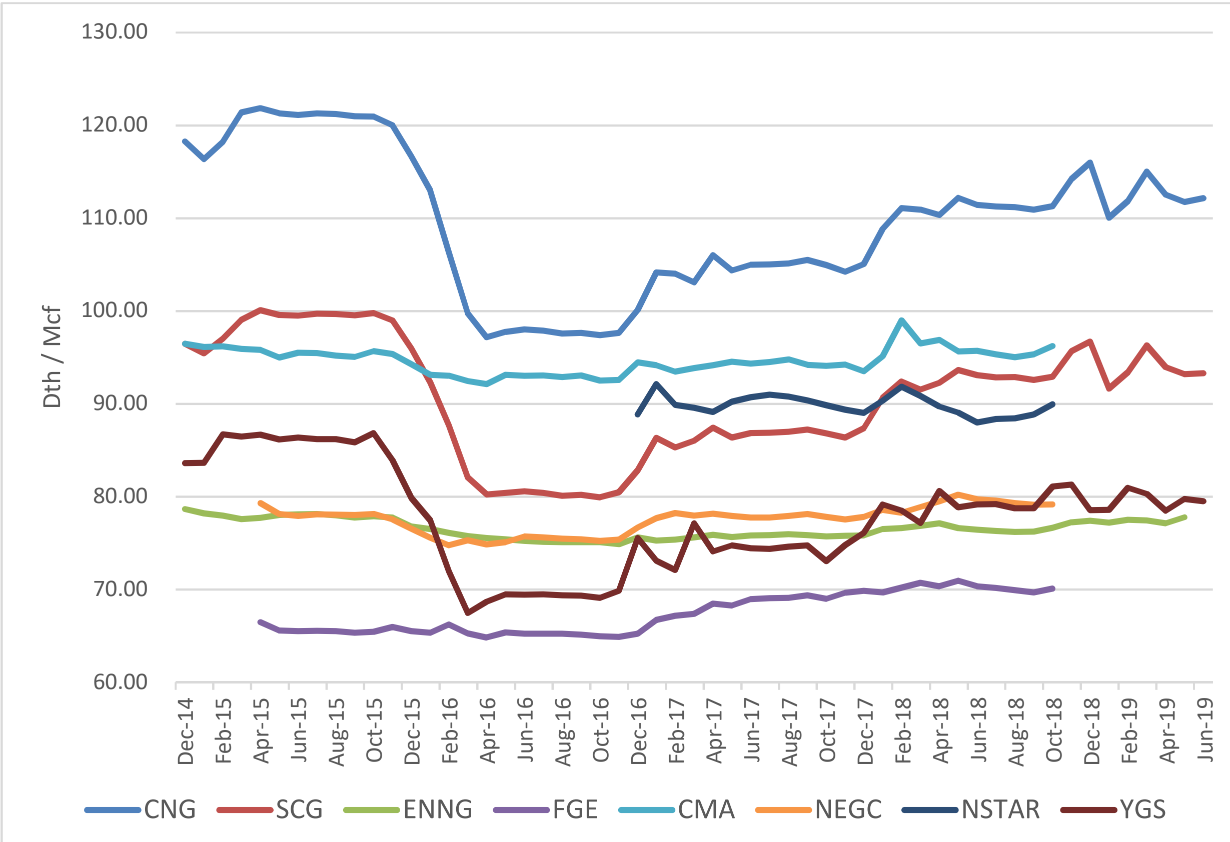
[7] This portion of the memorandum will be shared with the list of participants in recognition of their voluntary involvement in the study.

Table 7: Participating Local Gas Distribution Companies ("LDCs")

Utility	Abbreviation	Location	Approximate Number of Customers
Connecticut Natural Gas	CNG	Greater Hartford, CT and Greenwich, CT	180,000
Columbia Gas – MA	CMA	Springfield and Laurence, MA	325,000
Eversource Gas – MA	NSTAR	Central MA	290,000
Liberty – NH	ENNG	New Hampshire	95,000
National Grid – RI	NEGC	Rhode Island	55,000
The Southern Connecticut Gas Company	SCG	Greater New Haven and Bridgeport, CT	200,000
Unitil – MA	FGE	Fitchburg, MA	16,000
Eversource – CT	YGS	Across CT	200,000

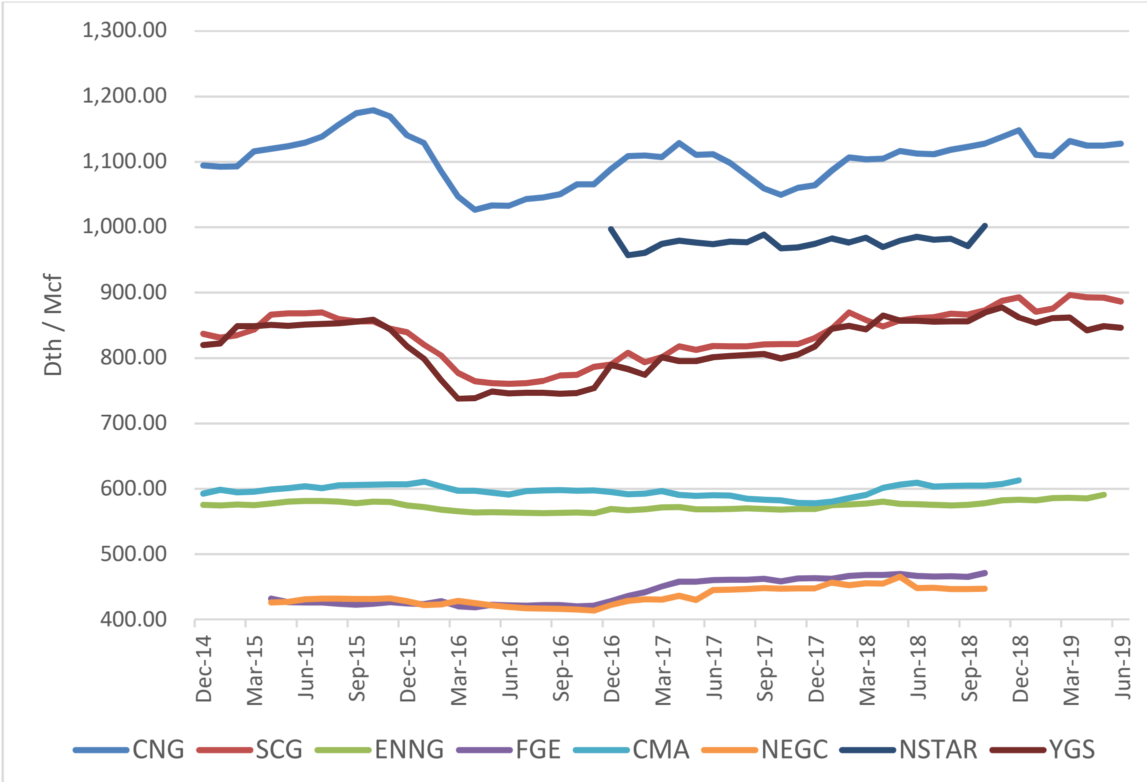
Monthly customer and usage data was obtained by rate class for as far back as January 2014. Concentric then calculated monthly UPC, then calculated a 12-month rolling total. Normalized consumption data was used where available. The data below represents summarized data for Residential (heat and non-heat), Commercial and Industrial customer classes.

Chart 4: Residential Use Per Customer Trends: 12-Month Rolling Total



The CNG, SCG and YGS trend lines are difficult to compare because only actual usage data was provided while all other survey respondents included both actual and normalized volumes. Still, the trend over the most recent three years is consistent with other LDCs.

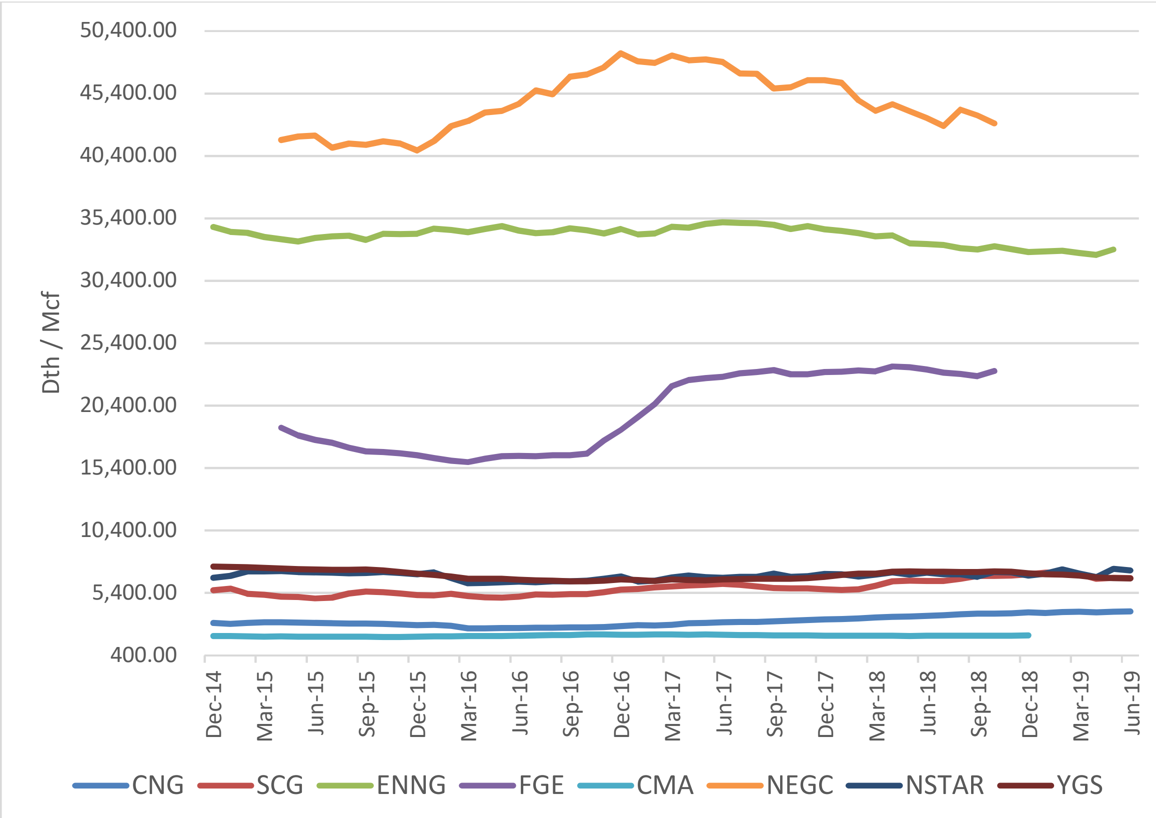
Chart 5: Commercial Use Per Customer[8] Trends: 12-Month Rolling Total



The Commercial trend exhibits a small upward trend for all LDCs except CMA, ENNG and NSTAR.

[8] NSTAR Gas represents a combined C&I UPC.

Chart 6: Industrial Use Per Customer Trends: 12-Month Rolling Total



The industrial class comparison is complicated by the fact that some of the utilities have appreciably different rate designs. For example, CNG, SCG and YGS's Industrial customers are served primarily under Rate LGS – Large General Service. This tariff does not carry a load factor distinction like the other participating LDCs tariffs. As such, the average UPC for these three LDCs appear much lower than those with more granular rate structures.

Appendix A contains individual use per customer graphs for each LDC.

SECTION VI. WEATHER VARIANCES AND THE REAL-TIME WNA

One of the audit tasks is to validate the accuracy of the real-time WNA adjustment. The real-time WNA is a customer-specific calculation that results in either a charge (when weather is warmer than normal) or a credit (when weather is colder than normal). The WNA is billed in the month in which the weather variance occurs, thus matching the charge or credit with the weather-related impact on the bill. Customer WNA billings is captured as a separate revenue component in the Company's revenue reporting, enabling a comparison between what was billed and what a class-level spreadsheet analysis produces. This comparison, although not expected to match perfectly, should indicate that the WNA is functioning properly or not. The results of the comparison between the real-time WNA and the Excel© based weather analysis is as follows:

Table 5: Comparison of Calculated Weather-Related Variance to the Real-Time WNA

Category	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19
Distribution Revenues	$6,176,999	$9,601,480	$12,370,924	$12,544,467	$11,461,724	$9,515,278	$6,468,216
Heating Degree Days	*Colder / (Warmer)*						
Actual HDD	601	983	1,085	1,160	1,059	710	415
Normal HDD	504	857	1,162	1,167	1,026	737	414
Difference	97	126	(77)	(8)	33	(27)	1
Variance %	19.3%	14.8%	-6.6%	-0.7%	3.2%	-3.7%	0.3%
Weather Variance	*(Credit) / Charge*						
Calculated WNA	($510,539)	($900,154)	$585,425	$61,848	($255,743)	$218,110	($7,368)
Billed WNA[1]	($65,581)	($926,070)	$568,805	$11,317	($172,550)	$414,250	$206,917
Difference	($444,958)	$25,916	$16,620	$50,531	($83,193)	($196,139)	($214,285)
% of Revenues							
Calculated Weather	-8.3%	-9.4%	4.7%	0.5%	-2.2%	2.3%	-0.1%
Billed WNA	-1.1%	-9.6%	4.6%	0.1%	-1.5%	4.4%	3.2%

Upon reviewing the above comparison, one would expect to see only a small monthly variation between the calculated WNA and the billed WNA. Further, the two methods should move in the same direction (both methods resulting in a credit, or both resulting in a debit). Additionally, the magnitude of the adjustment should reflect the difference in heating degree days ("HDD"). Concentric's findings is that each month from December 2018 through March 2019 appear reasonable, displaying a close correlation between methods.

The months of November 2018 and April 2019 showed material variances between actual billed WNA and the spreadsheet estimate. November has a significant amount of HDDs and the weather was significantly colder than normal (19.3% colder). This colder than normal HDD implies that customers would have their heating systems on for the majority of the month. The fact that the billed WNA was a comparatively small credit compared to the spreadsheet analysis (and weather was significantly colder than normal) indicates that there was likely a billing system issue. It is our understanding from the preliminary results meeting that there was in fact an implementation issue with the real-time WNA in November 2018 and a credit was subsequently applied in April 2019, which explains the variation in these two months.

SECTION VII. THE UNBILLED REVENUE METHODOLOGY AFFECTS THE RDM CALCULATION

Unbilled revenues reflect those sales that occurred in the calendar month but have yet to be billed to the customer. Accounting standards require companies to report revenues on a calendar basis. When companies such as ENNG utilize billing cycles, there is an inevitable mis-match between billed sales (which cross calendar months) and calendar sales. To remedy this mismatch, companies must estimate the value of these unbilled sales. There are three commonly used methods to estimate unbilled sales:

Method 1: Perform a system-wide calculation based on monthly actual gate station take data (the "send-out" method);

Method 2: Utilize a base-thermal methodology, which estimates unbilled revenues based on unbilled heating degree days (the "base-thermal" method), and

Method 3: Utilize actual end-of-month meter reads (the "AMI" method).

Of these three methods, ENNG utilizes method 1. This method is the simplest of the three as it relies on total gate station receipts and system-level adjustments to derive calendar sales. The shortcomings of this method is that results tend to be volatile across the months, and class-level detail is not estimated making variance analysis more difficult. Further, with an RDM that includes rate class revenue targets, performing the monthly RDM entry must be performed at the system level given the current method for unbilled estimation. This means that the Company's actual RDM calculation is different than its published tariff:

Table 6: RDM Methodology Comparison

Approved Tariff Methodology (RPC)	Actual Practice (Revenues)
Step 1: Calculate the difference between Actual RPC and Allowed RPC for each rate class	**Step 1**: Derive Allowed revenues by multiplying the Allowed RPC times the actual number of customers for each rate class and sum them
Step 2: Multiply the RPC differences derived in step 1 times the Actual number of customers in each rate class	**Step 2:** Compare Actual Revenues to Allowed Revenues derived in step 1
Step 3: The sum of the rate class revenue differences calculated in step 2 to derive the monthly decoupling adjustment	**Step 3**: Subtract Actual from Allowed revenues to derive the decoupling adjustment

Both methodologies result in the same decoupling adjustment amount. However, the lack of transparency to the class level for the RDM calculation makes variance analysis more difficult.

There was an error in the unbilled calculation in the months of November 2018 through April 2019. Billing cycle equivalent bills rather than calendar equivalent bills were inadvertently used in the unbilled calculation. This error contributed to significant monthly swings in the RDM revenues, as the mismatch in equivalent bills is captured by the RDM, which includes target RPC based on calendar equivalent bills. The monthly variations are as follows:

Table 7: Unbilled Equivalent Bills Error Impact on Monthly RDM Variation

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19
Customer Difference	(3,107)	2,160	3,215	4,977	(4,342)	(99)	(98)
Allowed RPC	$85.90	$112.91	$127.12	$119.83	$102.87	$69.23	$49.68
Dollar Impact	($266,901)	$243,919	$408,697	$596,338	($446,641)	($6,856)	($4,868)
Contribution to Monthly Unbilled Variance	**($266,901)**	**$510,820**	**$164,779**	**$187,641**	**($1,042,979)**	**$439,785**	**$1,988**

Once the error was discovered and corrected in April 2019 the large variation ended.

SECTION VIII. RECOMMENDATIONS

Recommendation 1: Any C&I rate review must be incorporated into the adjusted (rate year) equivalent bills calculation, and do not perform any rate reviews between rate cases.

Recommendation 2: Consider switching to a base-thermal unbilled methodology. This change will require some up-front investment in spreadsheet development but should help smooth monthly variances. This method will enable the Company to calculate its RDM consistent with its approved tariff and help with monthly variance analysis.

Recommendation 3: The real-time WNA should continue to be audited in the Company's billing system, particularly in the months when it is being applied to prorated bills (November and May).

SECTION IX. CONTACT US

Please contact me if there are any questions regarding this memorandum, or if we can provide further assistance.

Regards,

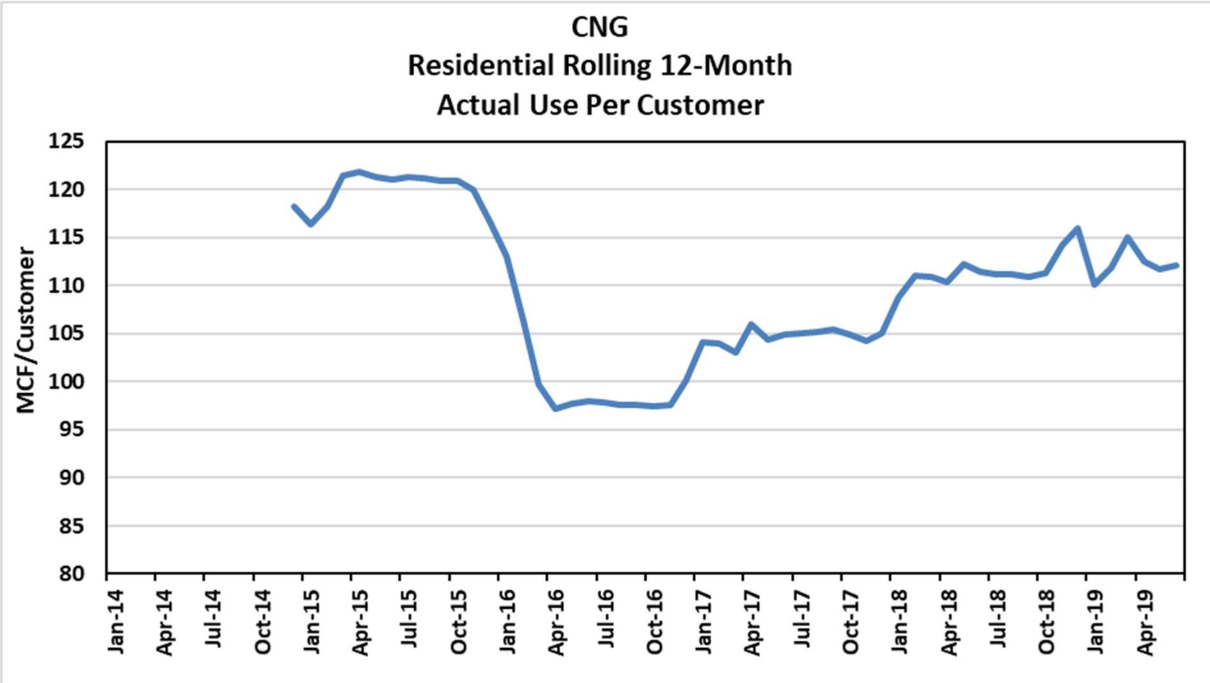
Gregg Therrien
Assistant Vice President
(508) 263-6284

APPENDIX A

DETAILED USE PER CUSTOMER CHARTS

PARTICIPATING LDCS

CNG


CNG
Residential Rolling 12-Month
Actual Use Per Customer
MCF/Customer
125
120
115
110
105
100
95
90
85
80
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Jan-16
Apr-16
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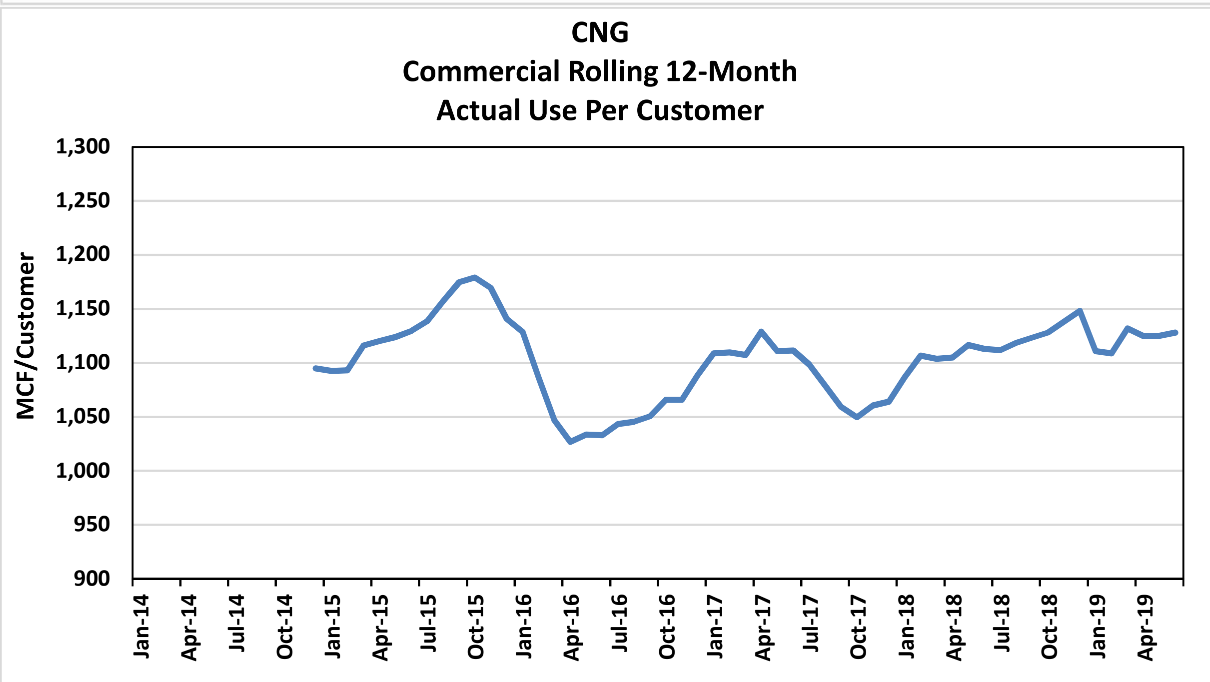
Oct-18
Jan-19
Apr-19


CNG
Commercial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
1,300
1,250
1,200
1,150
1,100
1,050
1,000
950
900
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Jan-16
Apr-16
Jul-16
Oct-16
Jan-17
Apr-17
Jul-17
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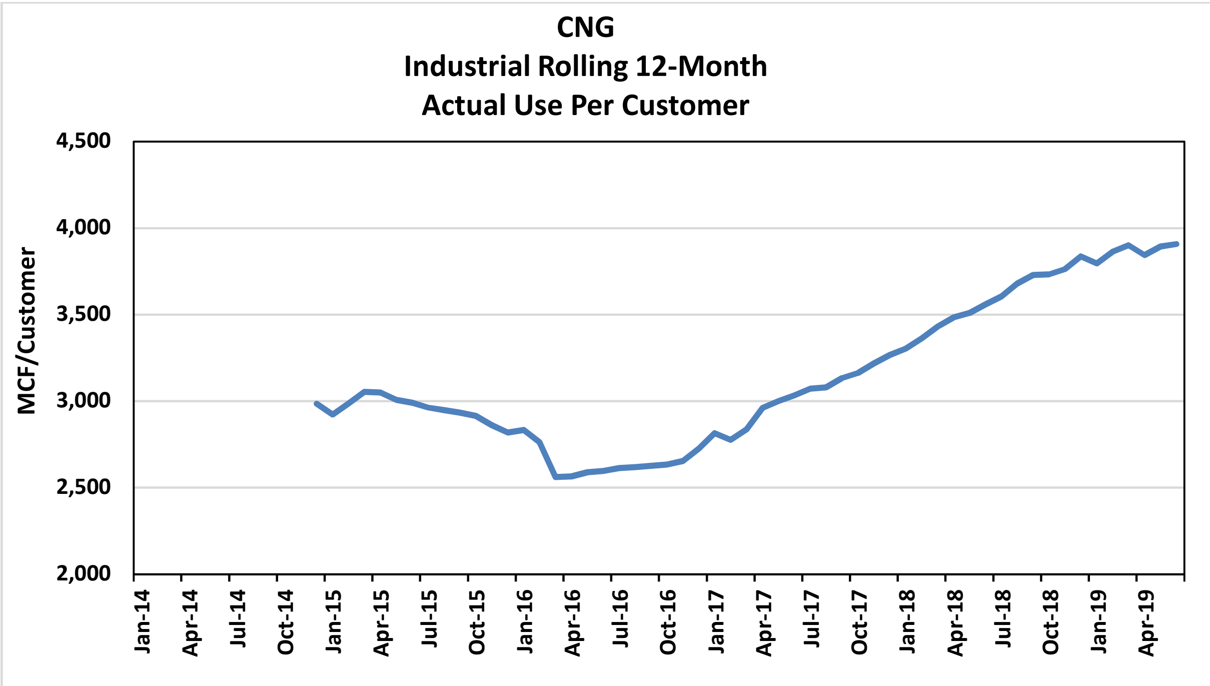
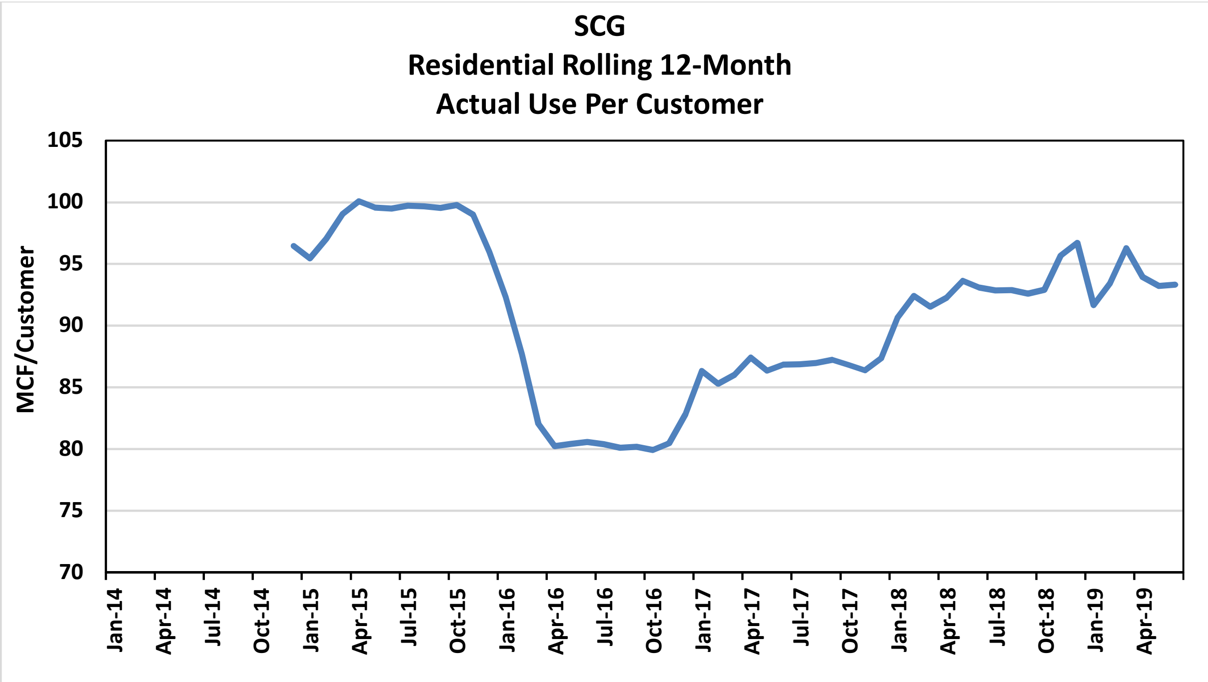
Oct-18
Jan-19
Apr-19


CNG
Industrial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
4,500
4,000
3,500
3,000
2,500
2,000
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Jan-16
Apr-16
Jul-16
Oct-16
Jan-17
Apr-17
Jul-17
Oct-17
Jan-18
Apr-18
Jul-18
Oct-18
Jan-19
Apr-19

SCG


SCG
Residential Rolling 12-Month
Actual Use Per Customer
MCF/Customer
105
100
95
90
85
80
75
70
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Jan-16
Apr-16
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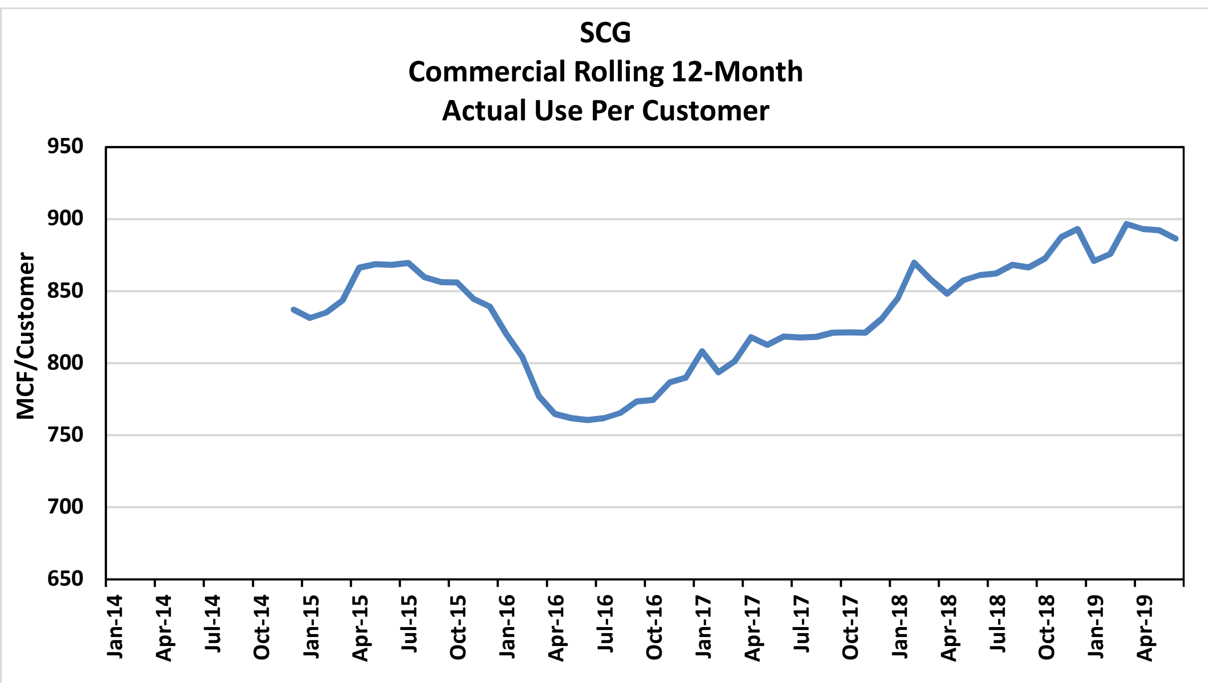
Oct-18
Jan-19
Apr-19


SCG
Commercial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
950
900
850
800
750
700
650
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Jan-16
Apr-16
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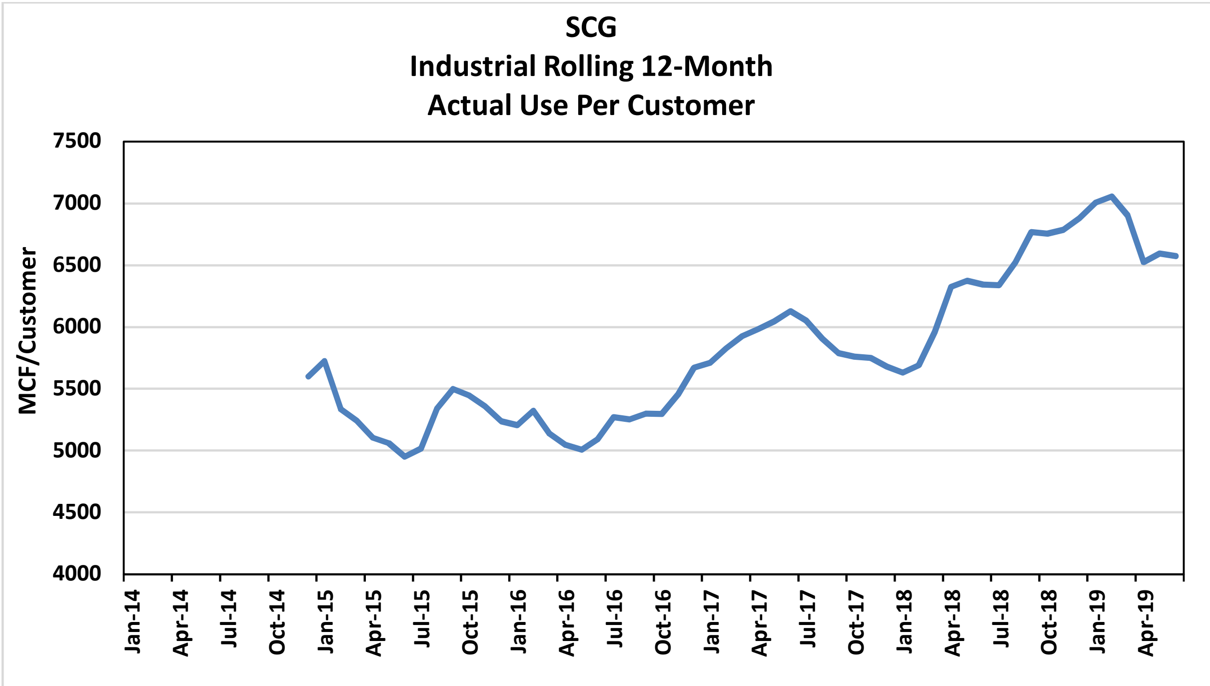
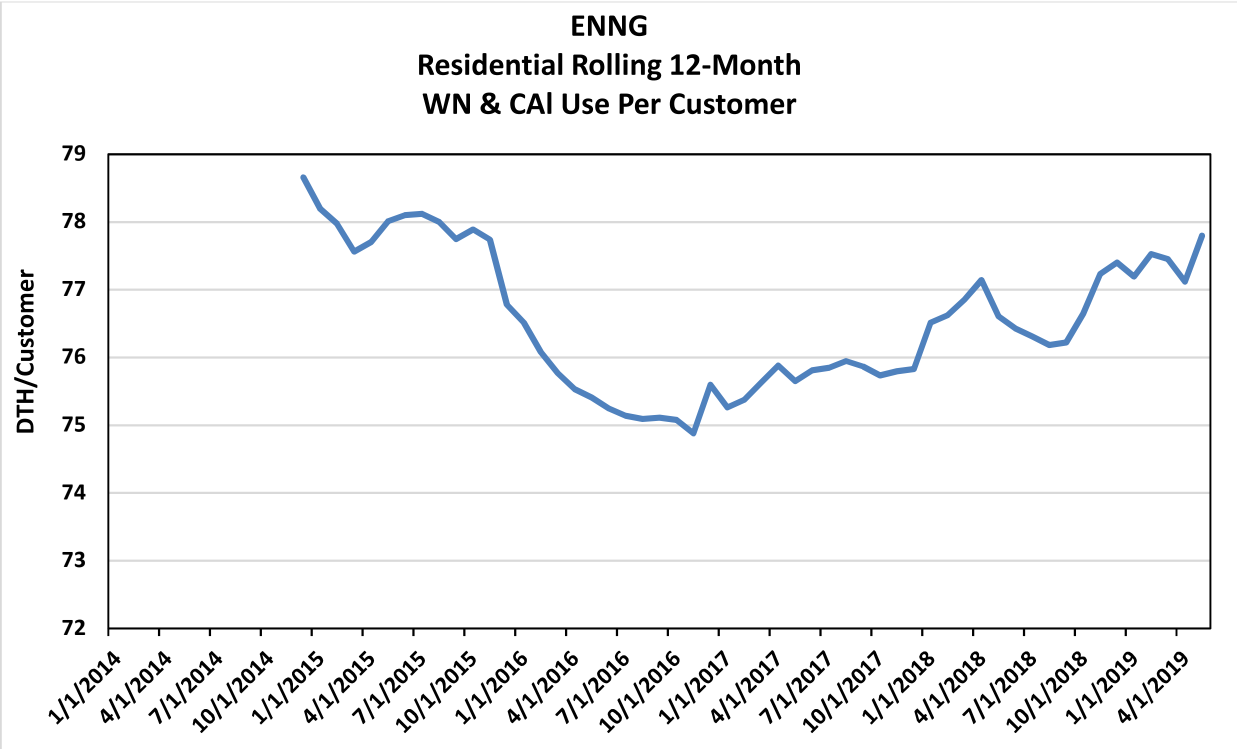
Oct-18
Jan-19
Apr-19


SCG
Industrial Rolling 12-Month
Actual Use Per Customer
MCF/Customer
7500
7000
6500
6000
5500
5000
4500
4000
Jan-14
Apr-14
Jul-14
Oct-14
Jan-15
Apr-15
Jul-15
Oct-15
Jan-16
Apr-16
Jul-16
Oct-16
Jan-17
Apr-17
Jul-17
Oct-17
Jan-18
Apr-18
Jul-18
Oct-18
Jan-19
Apr-19

ENNG


ENNG
Residential Rolling 12-Month
WN & CAl Use Per Customer
DTH/Customer
79
78
77
76
75
74
73
72
1/1/2014
4/1/2014
7/1/2014
10/1/2014
1/1/2015
4/1/2015
7/1/2015
10/1/2015
1/1/2016
4/1/2016
7/1/2016
10/1/2016
1/1/2017
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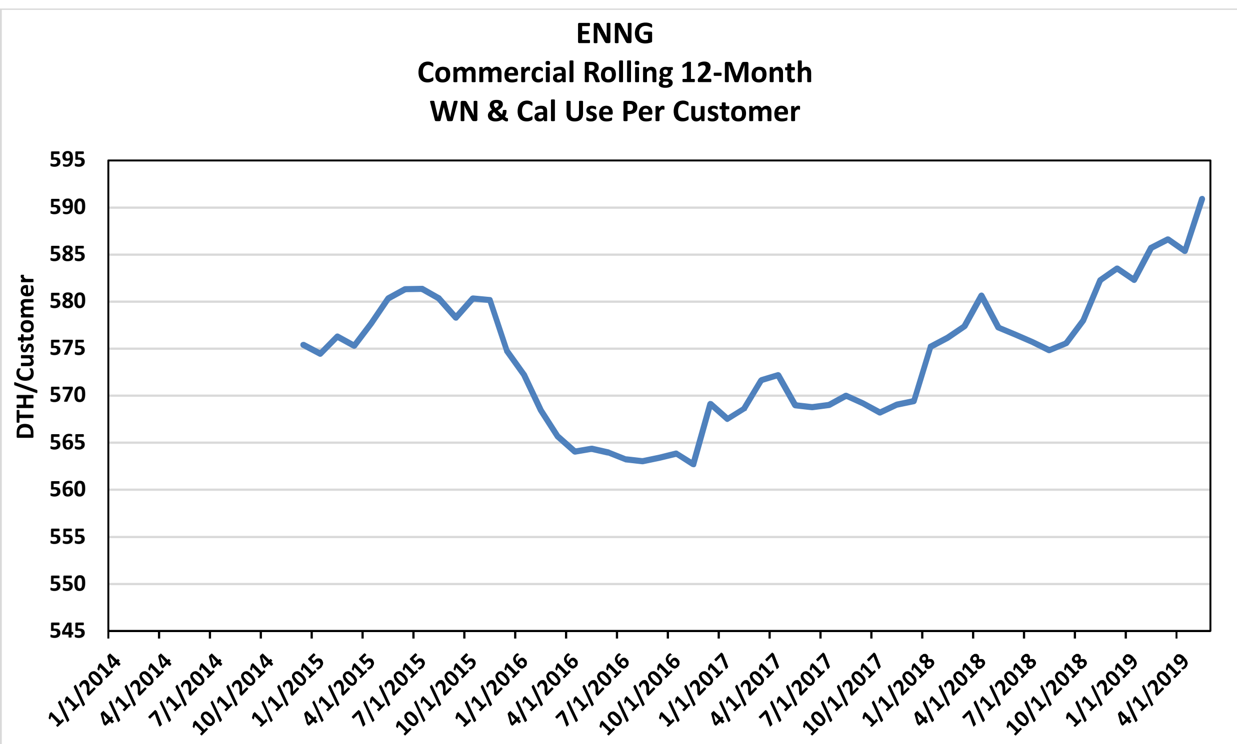
1/1/2019
4/1/2019


ENNG
Commercial Rolling 12-Month
WN & Cal Use Per Customer
DTH/Customer
595
590
585
580
575
570
565
560
555
550
545
1/1/2014
4/1/2014
7/1/2014
10/1/2014
1/1/2015
4/1/2015
7/1/2015
10/1/2015
1/1/2016
4/1/2016
7/1/2016
10/1/2016
1/1/2017
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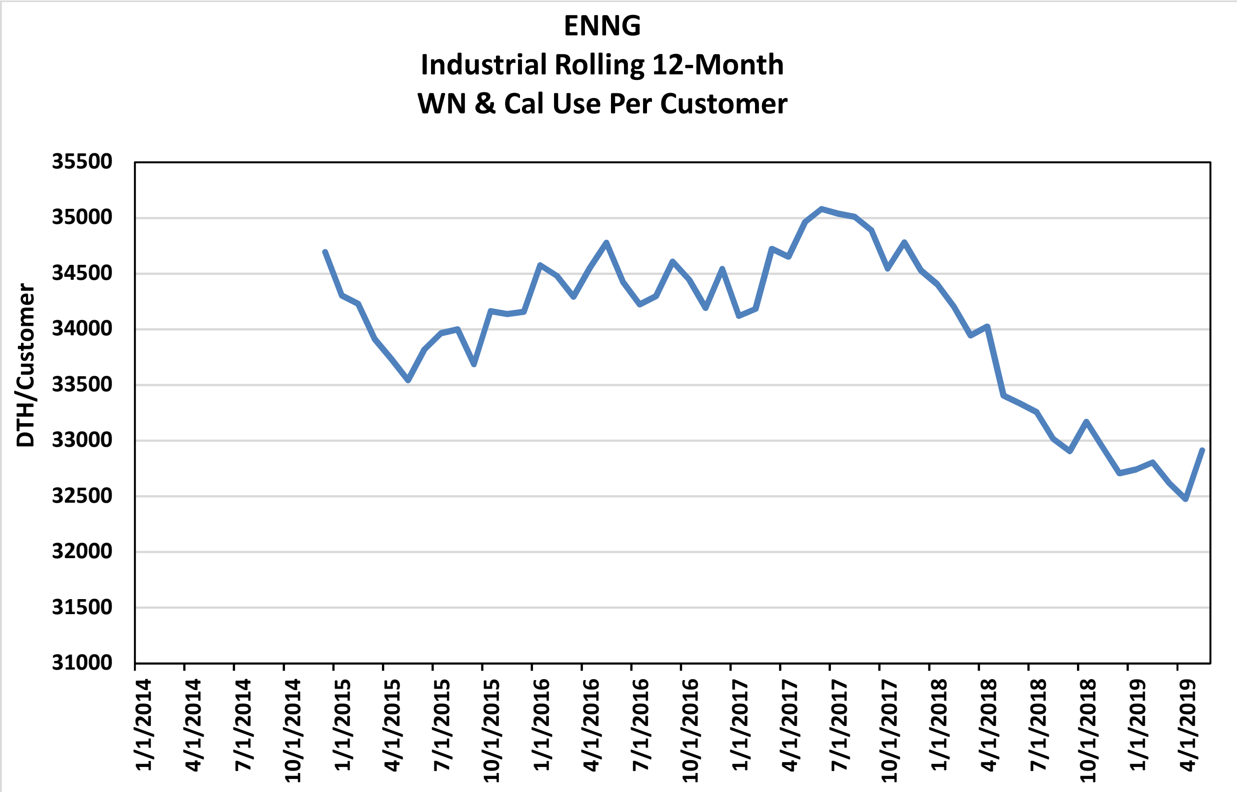
1/1/2019
4/1/2019


ENNG
Industrial Rolling 12-Month
WN & Cal Use Per Customer
DTH/Customer
35500
35000
34500
34000
33500
33000
32500
32000
31500
31000
1/1/2014
4/1/2014
7/1/2014
10/1/2014
1/1/2015
4/1/2015
7/1/2015
10/1/2015
1/1/2016
4/1/2016
7/1/2016
10/1/2016
1/1/2017
4/1/2017
7/1/2017
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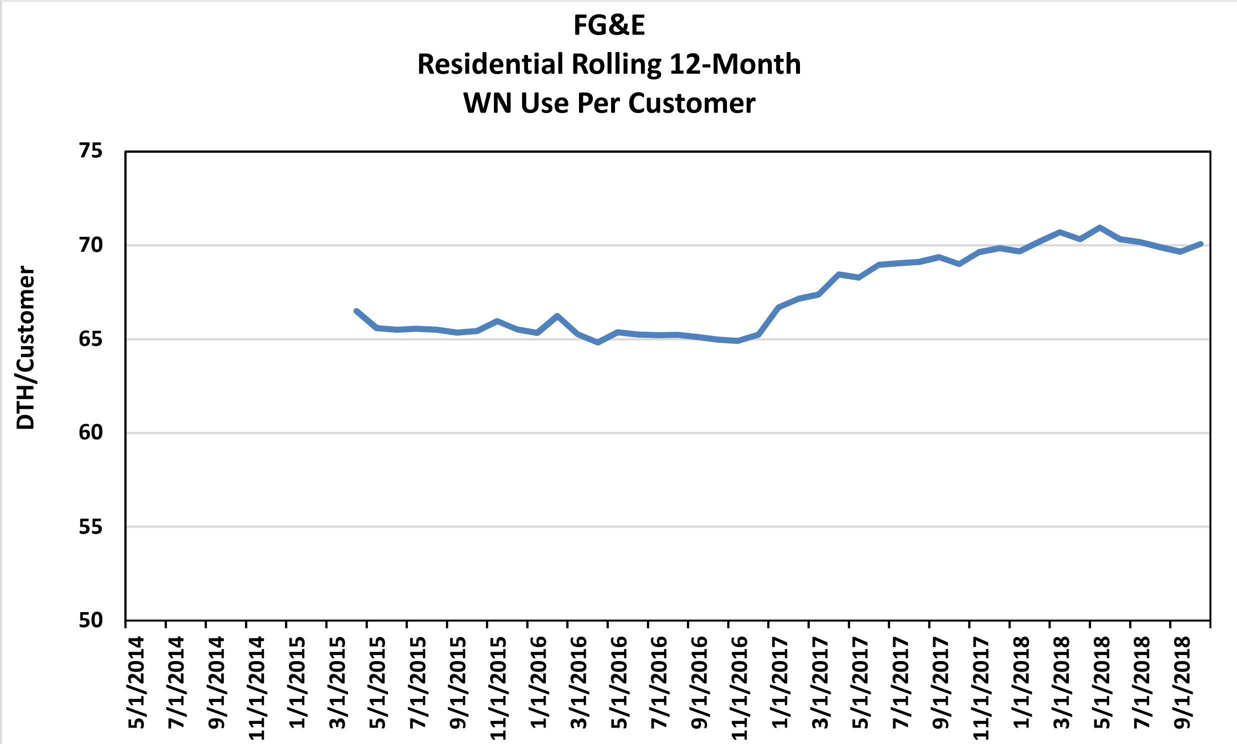
1/1/2018
4/1/2018
7/1/2018
10/1/2018
1/1/2019
4/1/2019

FGE


FG&E
Residential Rolling 12-Month
WN Use Per Customer
DTH/Customer
75
70
65
60
55
50
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
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3/1/2017
5/1/2017
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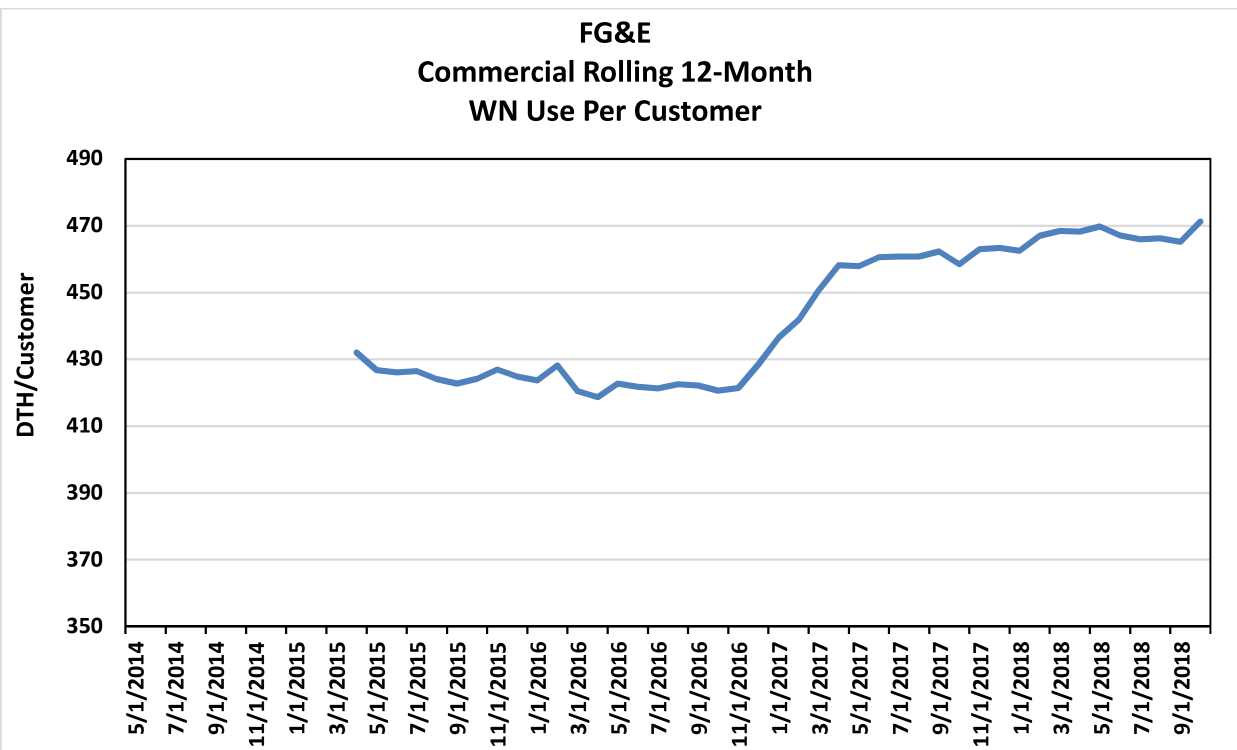
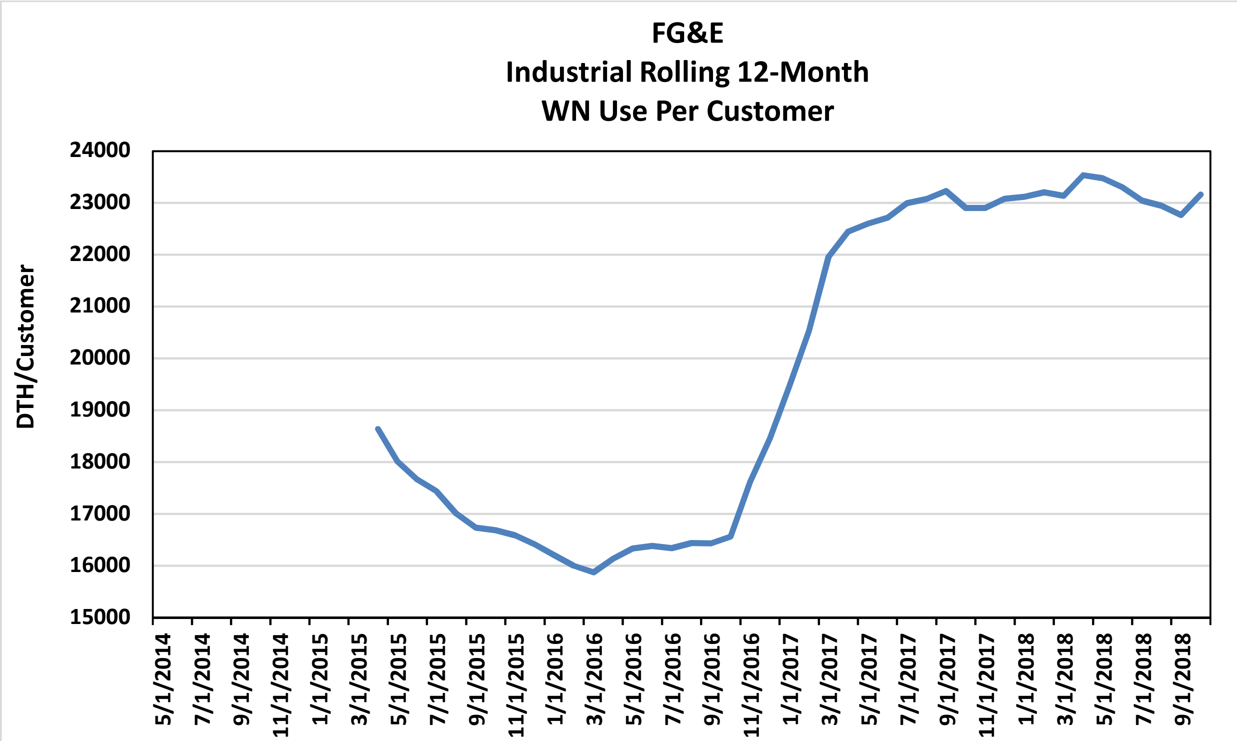
5/1/2018
7/1/2018
9/1/2018


FG&E
Commercial Rolling 12-Month
WN Use Per Customer
DTH/Customer
490
470
450
430
410
390
370
350
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


FG&E
Industrial Rolling 12-Month
WN Use Per Customer
DTH/Customer
24000
23000
22000
21000
20000
19000
18000
17000
16000
15000
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
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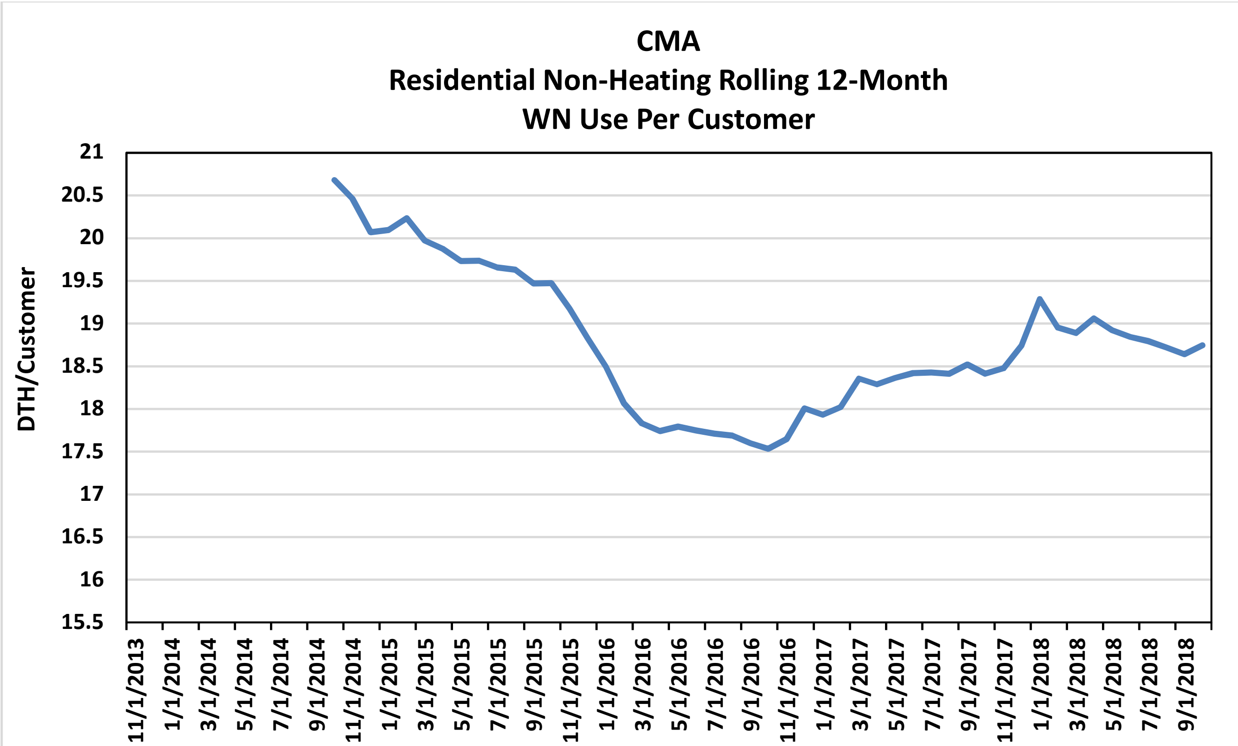
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

CMA


CMA
Residential Non-Heating Rolling 12-Month
WN Use Per Customer
DTH/Customer
21
20.5
20
19.5
19
18.5
18
17.5
17
16.5
16
15.5
11/1/2013
1/1/2014
3/1/2014
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
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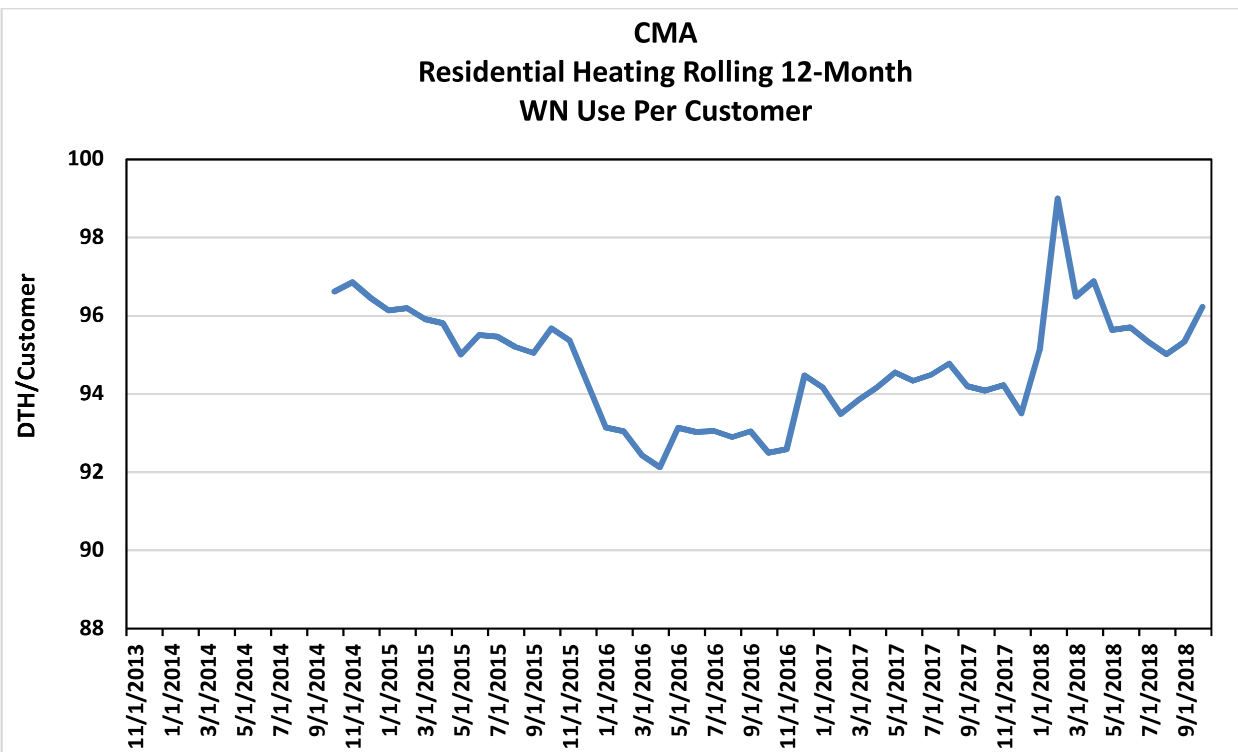
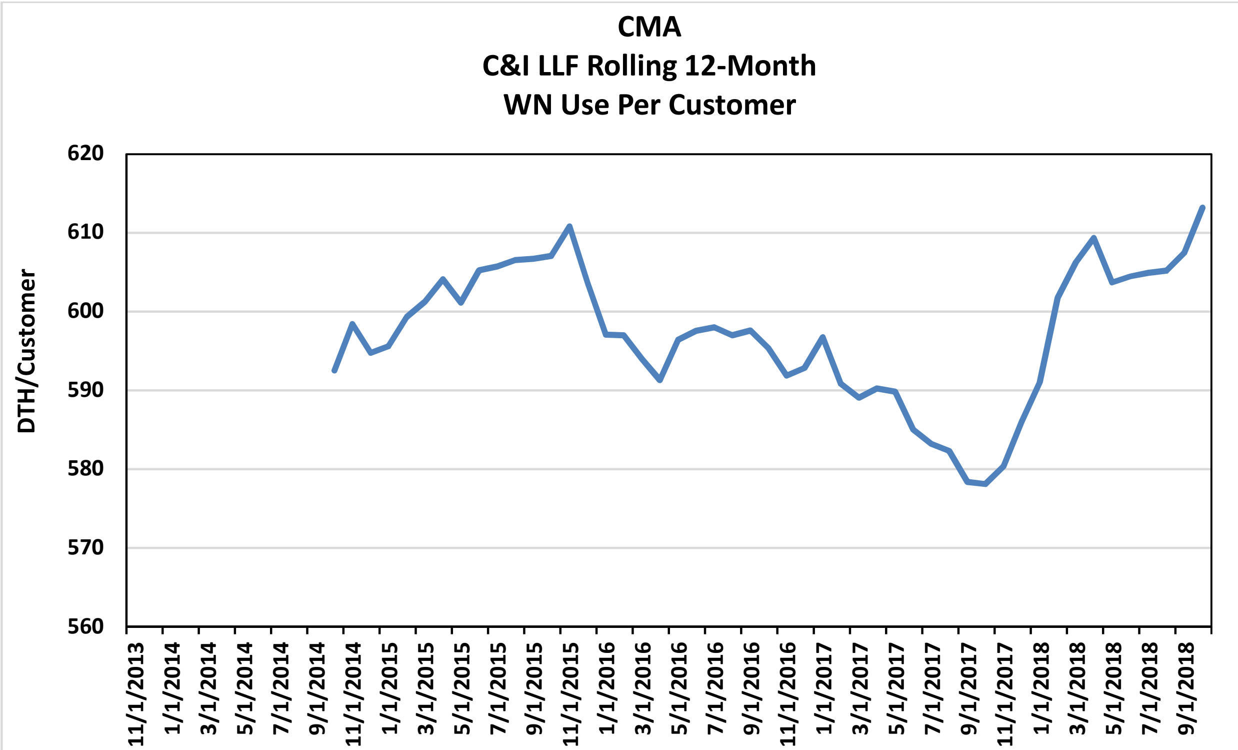
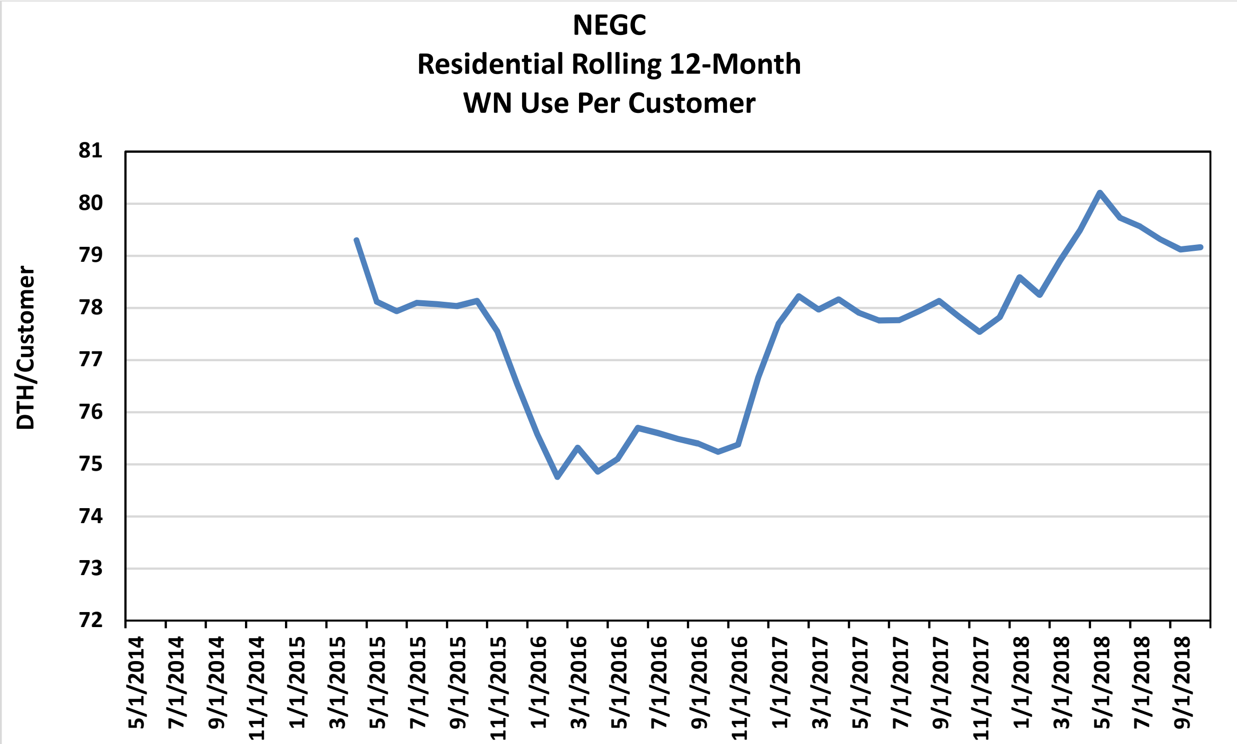
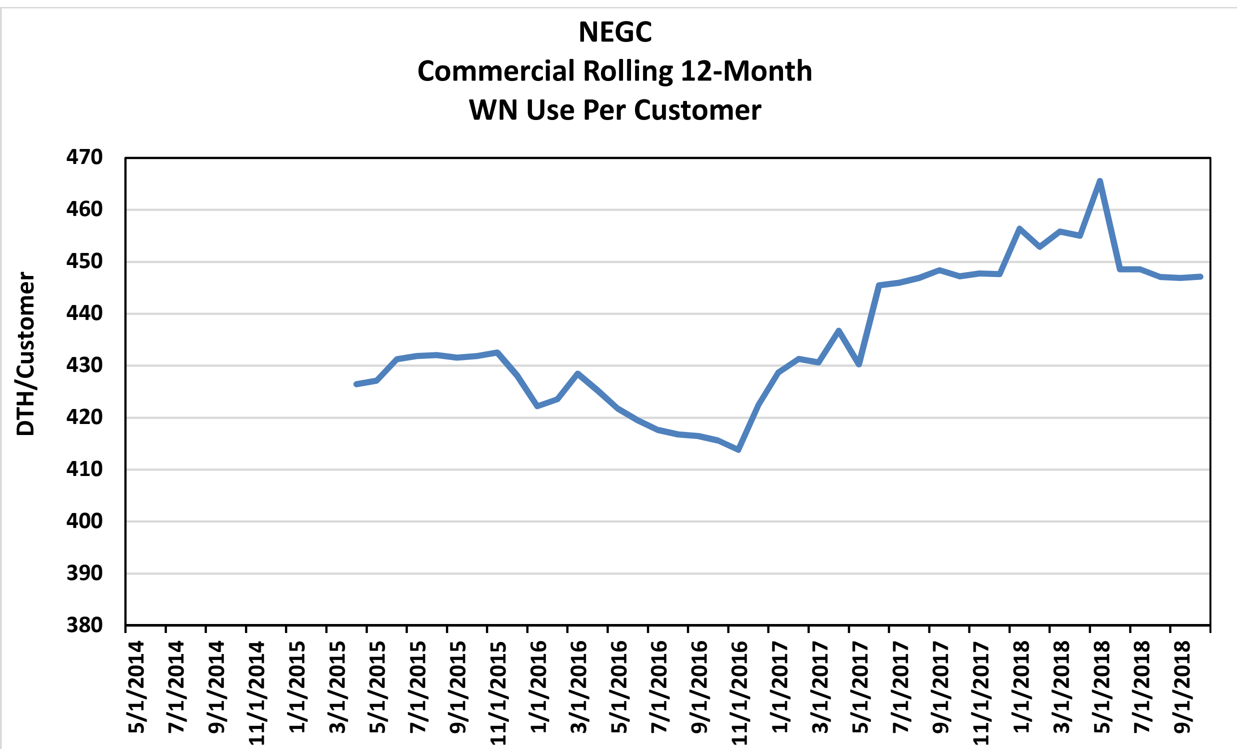
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

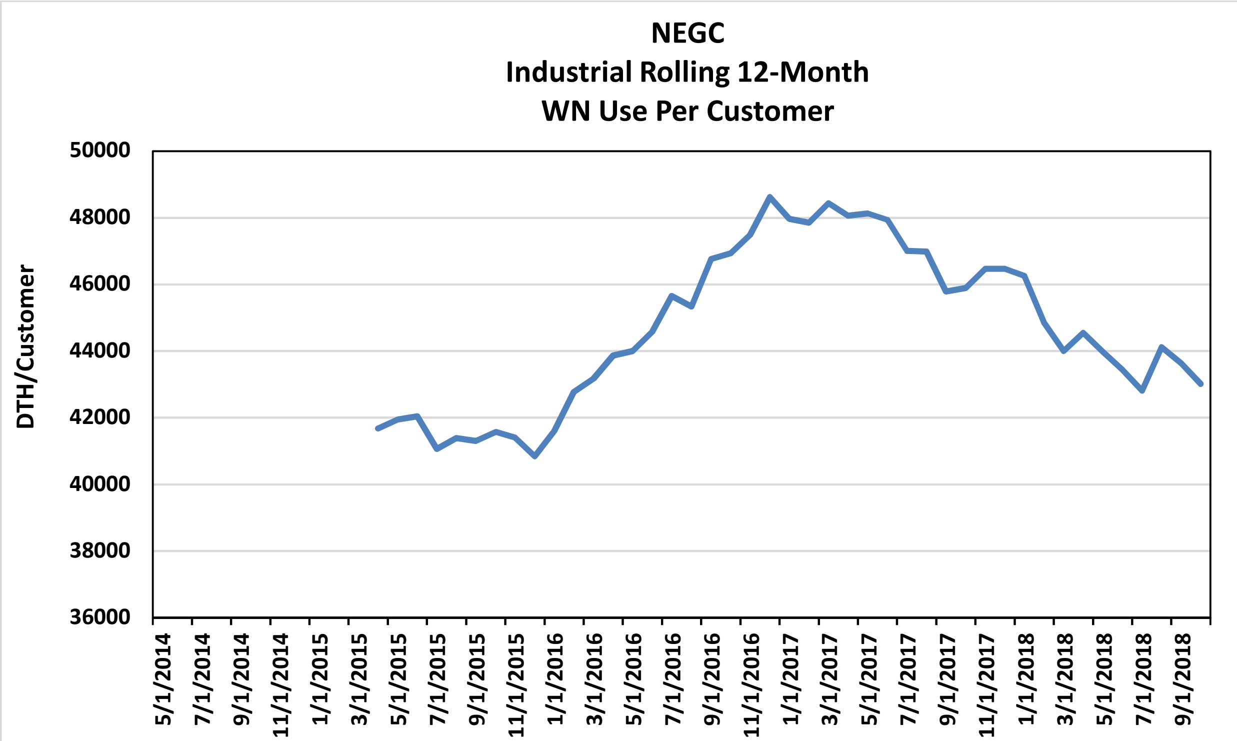

CMA
Residential Heating Rolling 12-Month
WN Use Per Customer
DTH/Customer
100
98
96
94
92
90
88
11/1/2013
1/1/2014
3/1/2014
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


CMA
C&I LLF Rolling 12-Month
WN Use Per Customer
DTH/Customer
620
610
600
590
580
570
560
11/1/2013
1/1/2014
3/1/2014
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

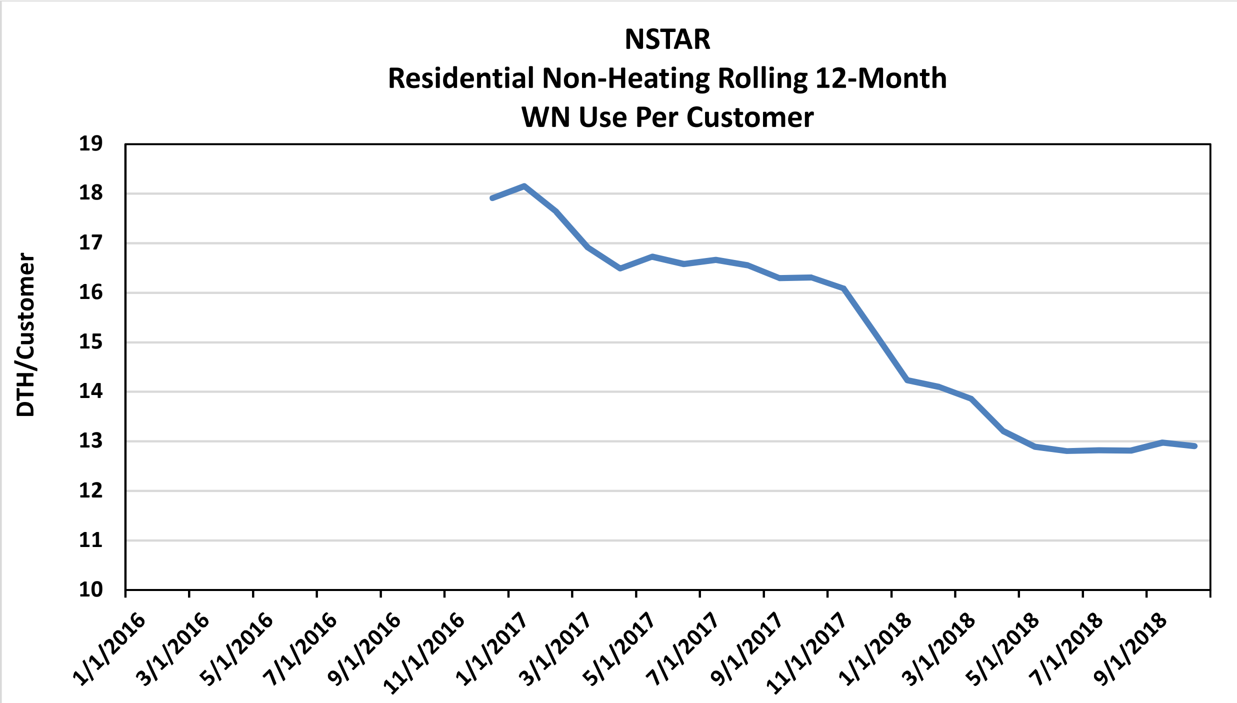
NEGC

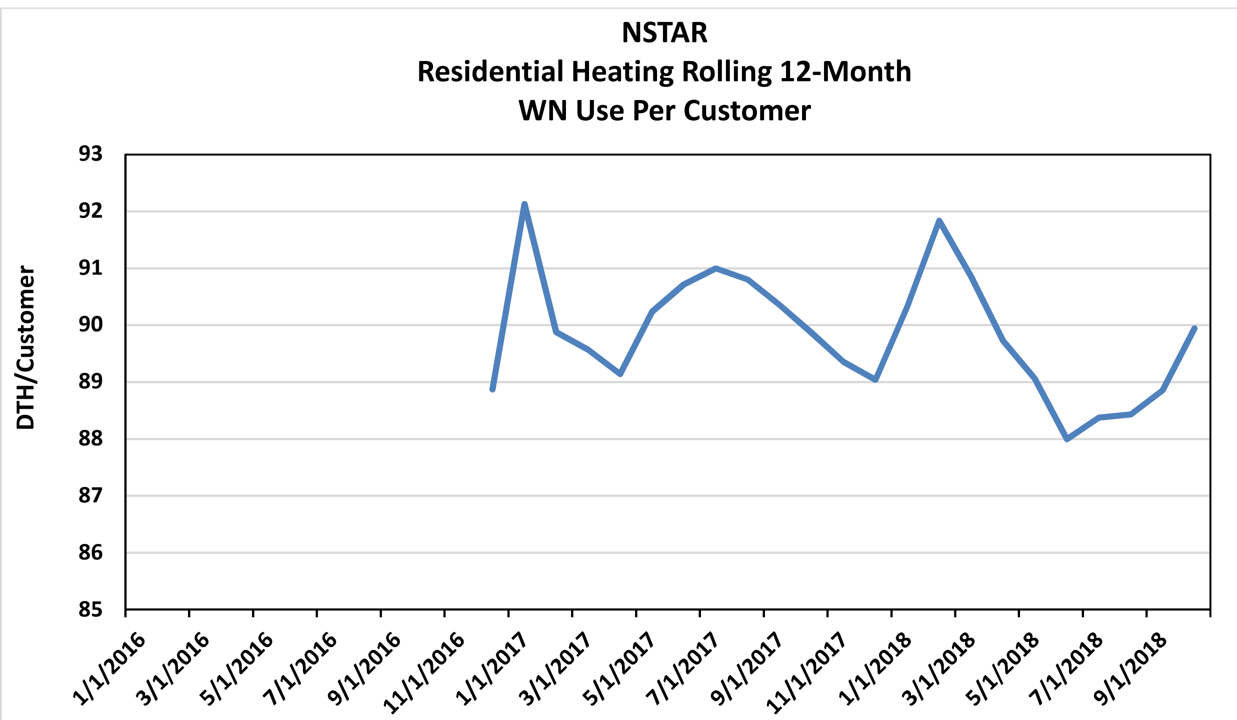

NEGC
Residential Rolling 12-Month
WN Use Per Customer
DTH/Customer
81
80
79
78
77
76
75
74
73
72
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


NEGC
Commercial Rolling 12-Month
WN Use Per Customer
DTH/Customer
470
460
450
440
430
420
410
400
390
380
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


NEGC
Industrial Rolling 12-Month
WN Use Per Customer
DTH/Customer
50000
48000
46000
44000
42000
40000
38000
36000
5/1/2014
7/1/2014
9/1/2014
11/1/2014
1/1/2015
3/1/2015
5/1/2015
7/1/2015
9/1/2015
11/1/2015
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

NSTAR


NSTAR
Residential Non-Heating Rolling 12-Month
WN Use Per Customer
DTH/Customer
19
18
17
16
15
14
13
12
11
10
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


NSTAR
Residential Heating Rolling 12-Month
WN Use Per Customer
DTH/Customer
93
92
91
90
89
88
87
86
85
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
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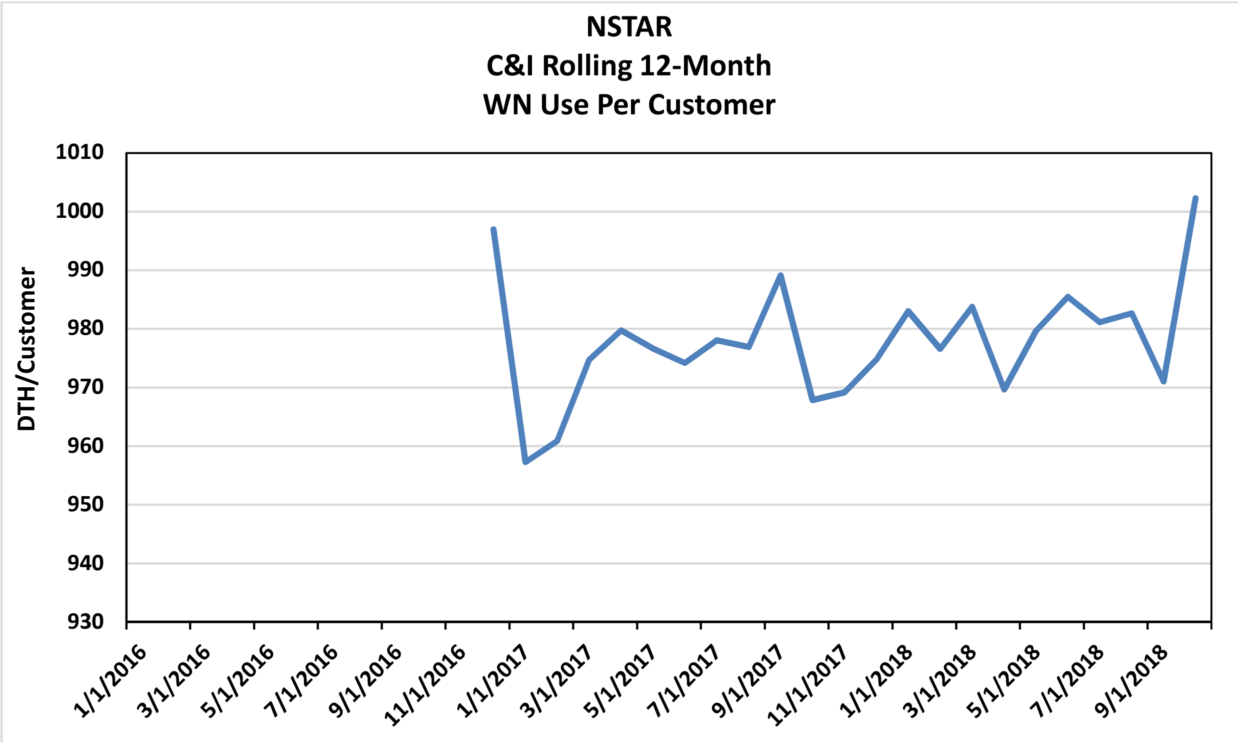
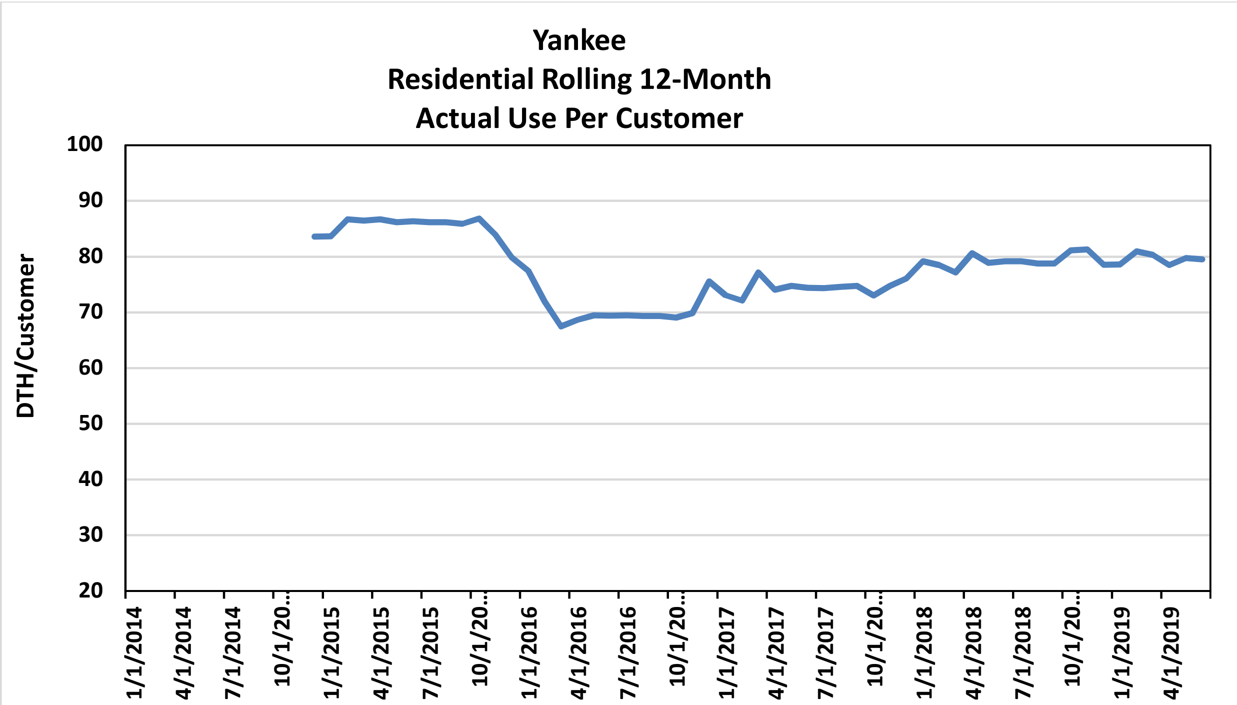
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018


NSTAR
C&I Rolling 12-Month
WN Use Per Customer
DTH/Customer
1010
1000
990
980
970
960
950
940
930
1/1/2016
3/1/2016
5/1/2016
7/1/2016
9/1/2016
11/1/2016
1/1/2017
3/1/2017
5/1/2017
7/1/2017
9/1/2017
11/1/2017
1/1/2018
3/1/2018
5/1/2018
7/1/2018
9/1/2018

YGS


Yankee
Residential Rolling 12-Month
Actual Use Per Customer
DTH/Customer
100
90
80
70
60
50
40
30
20
1/1/2014
4/1/2014
7/1/2014
10/1/20...
1/1/2015
4/1/2015
7/1/2015
10/1/20...
1/1/2016
4/1/2016
7/1/2016
10/1/20...
1/1/2017
4/1/2017
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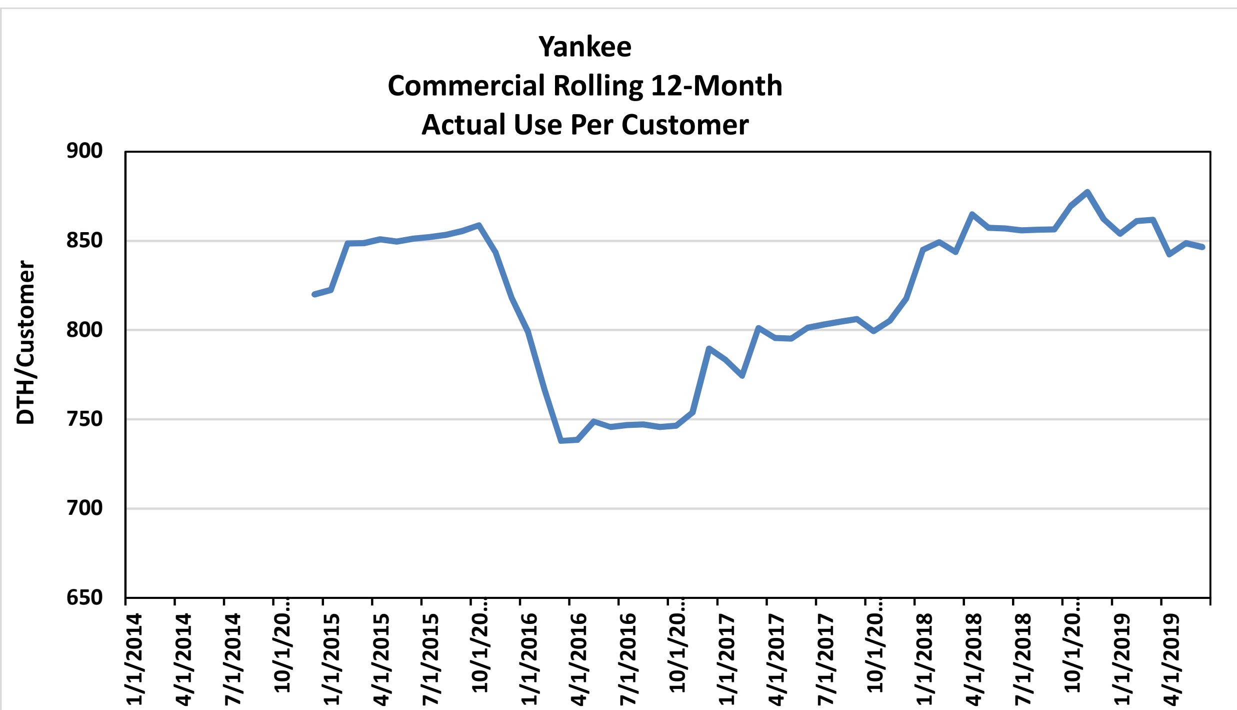
1/1/2019
4/1/2019


Yankee
Commercial Rolling 12-Month
Actual Use Per Customer
DTH/Customer
900
850
800
750
700
650
1/1/2014
4/1/2014
7/1/2014
10/1/20...
1/1/2015
4/1/2015
7/1/2015
10/1/20...
1/1/2016
4/1/2016
7/1/2016
10/1/20...
1/1/2017
4/1/2017
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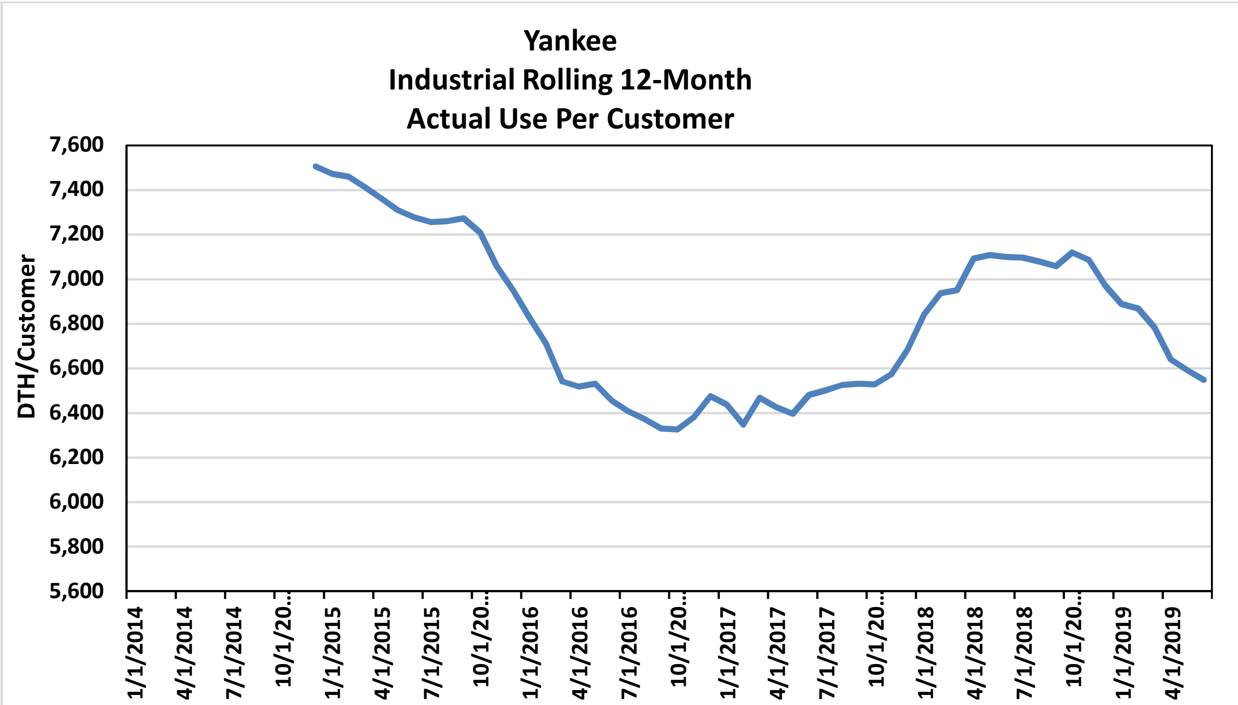
1/1/2019
4/1/2019


Yankee
Industrial Rolling 12-Month
Actual Use Per Customer
DTH/Customer
7,600
7,400
7,200
7,000
6,800
6,600
6,400
6,200
6,000
5,800
5,600
1/1/2014
4/1/2014
7/1/2014
10/1/20…
1/1/2015
4/1/2015
7/1/2015
10/1/20…
1/1/2016
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1/1/2017
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10/1/20…
1/1/2018
4/1/2018
7/1/2018
10/1/20…
1/1/2019
4/1/2019

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 20-105
Distribution Service Rate Case

Staff Data Requests - Set 3

Date Request Received: 12/16/20
Request No. Staff 3-5

Date of Response: 1/4/21
Respondent: Steven Mullen

REQUEST:

Ref. Mullen Testimony, Bates page II-198, line 12-20. Please explain the following:

a. How an increase in use per customer impacts the company under decoupling;

b. Why reclassification was needed after the last rate case, and provide any analysis the company did regarding the impact of reclassification.

RESPONSE:

a. In general, an increase in average use per customer will result in a revenue shortfall under decoupling. The decoupling mechanism transforms the actual seasonal fixed-variable customer class rate designs used for billing into an equivalent series of fixed rates—the allowed base revenues per bill (“RPC”). These transformations are done under specific circumstances at a specific point in time, which reflect the average use per customer at that point. Subsequent changes in the number of customers and their average use will be reflected in the decoupling mechanism as follows: If the average use decreases, the allowed base revenues under decoupling will exceed actual billings, and the deficiency will be recovered from customers through the Revenue Decoupling Adjustment Factor (“RDAF”); conversely, if the average use increases, the actual billings will exceed the allowed base revenues, and the excess will be returned to customers through the RDAF.

b. The “reclassification” referred to in Mr. Mullen’s Testimony, Bates page II-198, lines 15–19 was the result of the initial run of the Company’s Rate Review process, which was under development in 2016. The Rate Review process was not driven by the Docket DG 17-048 rate case, and its timing post-test year in early 2017 was entirely coincidental. The Rate Review process commences with a computer-generated weather-normalized historical billing comparison for each eligible customer of their present rate to one or more proposed rates based on rate class eligibility criteria. The results are then manually reviewed by customer care personnel, and if determined to be correct, each affected customer is notified and a rate change is made. The summary results of the computer-generated initial run are shown in Attachment Staff 3-5.

Row Labels	Customers	Sum of New_Amount	Sum of Cur_Amount	Difference	PctDiff
40-GC41	**489**	**$1,625,755**	**$1,477,848**	**$147,906**	**10.0%**
40-GC42	166	$1,126,603	$874,198	$252,405	28.9%
40-GC43	1	$38,336	$43,392	($5,056)	-11.7%
40-GC51	283	$291,000	$367,054	($76,053)	-20.7%
40-GC52	39	$169,814	$193,204	($23,390)	-12.1%
40-GC42	**529**	**$2,028,051**	**$3,232,280**	**($1,204,229)**	**-37.3%**
40-GC41	386	$952,523	$1,565,997	($613,474)	-39.2%
40-GC43	12	$395,895	$397,630	($1,736)	-0.4%
40-GC51	40	$62,497	$149,260	($86,763)	-58.1%
40-GC52	87	$494,259	$800,905	($306,646)	-38.3%
40-GC53	3	$81,360	$131,327	($49,967)	-38.0%
40-GC54	1	$41,518	$187,161	($145,643)	-77.8%
40-GC43	**18**	**$363,339**	**$456,199**	**($92,860)**	**-20.4%**
40-GC42	15	$248,808	$294,196	($45,387)	-15.4%
40-GC53	3	$114,531	$162,004	($47,473)	-29.3%
40-GC51	**437**	**$722,918**	**$528,731**	**$194,187**	**36.7%**
40-GC41	384	$457,086	$366,661	$90,425	24.7%
40-GC42	19	$124,205	$60,291	$63,915	106.0%
40-GC52	34	$141,627	$101,780	$39,847	39.2%
40-GC52	**97**	**$650,380**	**$560,023**	**$90,356**	**16.1%**
40-GC41	17	$39,681	$49,875	($10,194)	-20.4%
40-GC42	37	$387,181	$238,836	$148,345	62.1%
40-GC43	1	$28,061	$15,953	$12,108	75.9%
40-GC51	35	$64,335	$108,873	($44,539)	-40.9%
40-GC53	3	$67,820	$53,140	$14,680	27.6%
40-GC54	4	$63,302	$93,346	($30,044)	-32.2%
40-GC53	**10**	**$172,517**	**$189,903**	**($17,386)**	**-9.2%**
40-GC41	1	$1,274	$8,148	($6,874)	-84.4%
40-GC42	4	$59,079	$55,844	$3,236	5.8%
40-GC43	2	$66,955	$49,425	$17,530	35.5%
40-GC52	1	$12,352	$17,495	($5,142)	-29.4%
40-GC54	2	$32,856	$58,992	($26,136)	-44.3%
40-GC54	**9**	**$538,814**	**$254,359**	**$284,455**	**111.8%**
40-GC41	1	$1,911	$8,059	($6,148)	-76.3%
40-GC43	1	$45,249	$17,216	$28,033	162.8%
40-GC52	1	$4,298	$8,508	($4,210)	-49.5%
40-GC53	6	$487,355	$220,576	$266,779	120.9%
40-GR1	**149**	**$84,619**	**$54,898**	**$29,721**	**54.1%**
40-GR3	149	$84,619	$54,898	$29,721	54.1%
40-GR3	**2,375**	**$647,255**	**$975,686**	**($328,431)**	**-33.7%**
40-GR1	2,375	$647,255	$975,686	($328,431)	-33.7%
Grand Total	**4,113**	**$6,833,648**	**$7,729,928**	**($896,281)**	**-11.6%**

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty

DG 20-105
Distribution Service Rate Case

Staff Technical Session Data Requests - Set 3

Date Request Received: 2/8/21	Date of Response: 2/24/21
Request No. Staff TS 3-9	Respondent: Heather Tebbetts

REQUEST:

Please provide a copy of the most recent 5-year capital spending plan.

RESPONSE:

Please see Attachment Staff TS 3-9.xlsx for the Company's most recent capital spending plan.

As shown in the attachment, the capital spending plan includes a variety of investments, many of which are standard types of projects and programs included in the annual capital budget, such as replacement of leak-prone mains and services, new services, meter purchases, and city/state construction. Also included in the annual capital budget are the gas system planning and reliability investments and the gas system supply investments that were discussed during the early February technical sessions. Also, consistent with the response to OCA 3-10, the Company has included its planned investment in SAP (referred to as Customer First), which is a critical project to replace the current Customer Information System, accounting system, and other various operations and work planning systems. As noted in the response to OCA 3-10, the Company is in the process of finalizing its analysis of the overall costs and benefits of the Customer First project and will have that analysis available by the end of the first quarter of 2021.

Liberty Utilities (EnergyNorth Natural Gas) d/b/a Liberty
Attachment Staff TS 3-9 5-Year Capital Spending Plan

Project Description	Priority	FY2021	FY2022	FY2023	FY2024	FY2025
Reserve for Unidenfitied Mandated Projects	2. Mandated	200,000	206,000	206,000	212,180	212,180
Meter Protection Program	2. Mandated	500,000	300,000	300,000	300,000	300,000
Cathodic Protection Program	2. Mandated	500,000	620,000	849,750	849,750	849,750
Replacement Services Random (Non Leaks)	2. Mandated	450,000	550,000	592,250	592,250	592,250
Replacement Services Random (Due to Leaks)	2. Mandated	550,000	750,000	750,000	750,000	750,000
Corrosion & Miscellaneous Fitting	2. Mandated	250,000	108,150	111,395	111,395	111,395
Valve Installation/Replacement	2. Mandated	60,000	75,000	75,000	75,000	75,000
Leak Repairs	2. Mandated	1,750,000	1,262,745	1,300,628	1,339,647	1,379,836
Main Replacement LPP	4. Regulatory Programs	8,601,098	17,380,841	19,420,363	21,773,837	24,362,658
Main Replacement LPP-Restoration	4. Regulatory Programs	4,069,903	4,014,376	4,114,376	4,114,376	4,114,376
Main Replacement Fitting LPP	5. Discretionary	740,501	1,330,636	1,370,555	1,411,672	1,454,022
K Meter Replacement Program	5. Discretionary	350,000	3,090,000	3,182,700	3,278,181	3,491,328
Aldyl-A Replacement Program	5. Discretionary	200,000	966,543	1,063,197	1,169,517	1,286,468
Main Replacement Reactive	5. Discretionary	600,000	653,679	719,047	790,952	790,952
Dispatch and Control Center	5. Discretionary	10,000	10,000	10,300	10,300	10,300
Purchase Misc Capital Equipment & Tools	1. Safety	200,000	280,000	280,000	280,000	280,000
Regulator removal Hi line LOU	5. Discretionary	50,000	250,000	250,000	250,000	250,000
SCADA Capital Improvements	5. Discretionary	80,000	80,000	82,400	82,400	82,400
Upgrade Synergi Software	5. Discretionary	65,000	65,000	65,000	65,000	65,000
Inactive Service Program	2. Mandated	75,000	75,000	75,000	75,000	75,000
Main Replacement City/State Construction	2. Mandated	4,654,819	2,374,131	2,611,544	2,872,699	3,159,969
Nashua Paving	5. Discretionary	760,000	-	-	-	-
Service Replacement Fitting City/State Construction	2. Mandated	303,000	153,378	157,980	162,719	167,601
LNG/LPG Capital Improvements	2. Mandated	100,000	103,000	106,090	106,090	106,090
Reserve for Unidentified Growth ENG	3. Growth	1,500,000	1,342,250	1,542,250	1,542,250	1,542,250
Gas System Control & Regulation (ENG)	5. Discretionary	425,000	-	-	-	-
Pre-Code Stee Pipe Protection Program/Replacement	2. Mandated	200,000	500,000	500,000	500,000	500,000
IT - Software, Equipment & Infrastructure	5. Discretionary	50,000	50,000	50,000	50,000	50,000
Gas System Planning & Reliability	5. Discretionary	2,900,000	4,500,000	13,900,000	6,380,000	7,400,000
IT Systems Allocations - Corporate	5. Discretionary	450,000	500,000	500,000	500,000	500,000
Dresser Coupling Replacement Program	2. Mandated	500,000	487,245	501,862	516,918	532,425
Growth New Main	3. Growth	4,534,000	4,631,100	4,731,100	4,831,100	4,982,100
New Reinforcement Main for Growth ENG	3. Growth	-	800,000	1,000,000	1,000,000	1,000,000
Growth Fitting	3. Growth	1,754,528	1,304,528	1,304,528	1,504,528	1,504,528
New Service Residential	3. Growth	3,252,817	3,038,850	3,038,850	3,138,850	3,138,850
New Service Comm/Industrial	3. Growth	1,086,333	1,067,723	1,067,723	1,067,723	1,067,723
Marketing & Sales	3. Growth	-	150,000	150,000	150,000	150,000
Transportation Fleet and Equipment Purchases	5. Discretionary	2,013,000	800,000	200,000	866,000	1,500,000
Meter Work Project (Meter Purchases)	2. Mandated	1,150,000	1,020,545	1,220,545	1,220,545	1,220,545
EN Facilities Capital Improvements	5. Discretionary	600,000	600,000	600,000	600,000	600,000
Install Security Equipment - EN Facilities	2. Mandated	-	103,000	26,523	26,523	20,403
Facility Improvements & Additions - Various	2. Mandated	-	-	106,090	406,090	400,090
Install Solar Panels - EN Buildings	5. Discretionary	-	-	300,000	-	-
Repave Parking Lot - Manchester	5. Discretionary	-	800,000	-	-	-
AMI/AMR	5. Discretionary	-	-	-	-	4,031,440
2' Jamesbury replacement program	1. Safety	-	60,000	60,000	60,000	60,000
RTU Replacement Program	5. Discretionary	60,000	60,000	60,000	60,000	60,000
Customer First/SAP	5. Discretionary	-	35,904,324	-	-	-
Finance Unalloc Burden	5. Discretionary	500,000	703,428	703,531	703,351	703,132
Gas Supply System Enhancements	5. Discretionary	-	17,800,000	5,000,000	27,700,000	-
GPS Mapping Equipment	5. Discretionary	50,000	-	-	-	-
Service Mapping Project	5. Discretionary	300,000	-	-	-	-
Flir Cameras - Security -Manchester (Nashua)	5. Discretionary	900,000	-	-	-	-
SAP-Ariba EN Portion Procure to Pay Software	5. Discretionary	215,000	-	-	-	-
FLIR-Tilton	5. Discretionary	440,000	-	-	-	-
	Total	47,999,999	110,921,473	74,256,576	93,496,840	74,930,060

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

DG 17-048
Distribution Service Rate Case

Staff Data Requests – Set 7

Date Request Received: 9/21/17
Request No. Staff 7-9

Date of Response: 10/5/17
Respondent: Paul Normand

REQUEST:

Reference testimony of Paul M. Normand, attachment PMN-2, Bates page 445: Given that average life, net salvage, and similar curve are being used for this account in the current and most recent depreciation study:

a. In your expert opinion, what are the possible reasons for the very large swings in reserve variances?
b. Does the Company's proposed level reserve variance amortization address the account level variances?
c. What are your recommendations to minimize such swings in reserve variances at the account level?

RESPONSE:

a. The large swing in the reserve variance is primarily from two accounts: Mains (367.00) and Services (380.00) since the Company's last study. The large deviation is a direct result of the very large plant dollar increases for these accounts (Mains $98M, Services $66M) driven primarily by the mandated replacement program (CIBS) which is expected to continue for some period of time. As a result, we expect that this behavior will continue to be exhibited in a similar fashion as has been experienced but at a lower level since the recent amortization from the last study will be terminated.
b. The Company's proposed amortization factors consider many additional aspects that go well beyond a typical depreciation study to consider. The depreciation study itself continues to recommend a two cycle amortization of the variances without any consideration for the impact to the reserve variances from the last ten years.
c. As I mentioned in response part a. above, the Company's continued replacement program is impacting primarily two accounts which will continue to require large plant investment well into the foreseeable future. The current results and variances will continue to be exhibited, but a reduced level for the immediate future with the following options capable of minimizing future variances:

1) Change the current depreciation model from a Whole Life (WL) to a Remaining Life (RL) model which is well recognized in the industry and regulators alike. This calculation incorporates the existing reserve levels for each account in deriving the accrual rate for each account. In this manner, the RL approach is self-correcting over time.
2) If maintaining the WL approach is required, then consider establishing a collar or a threshold band width for the variance such that no amortization would occur unless the variance is in excess of 5 or 10% of the theoretical level.
3) More frequent studies for selected accounts to evaluate the variance levels. This would control the costs somewhat while providing additional information to regulators with respect to the larger and faster growing plant accounts, especially where mandated requirements are in effect.