BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East
Suite 350
St. Paul, Minnesota 55101-2147

MPUC Docket No. G-008/GR-21-435
OAH Docket No. 65-2500-37994

In the Matter of the Application of CenterPoint Energy Resources Corp d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota

DIRECT TESTIMONY AND SCHEDULES OF THE MINNESOTA OFFICE OF THE ATTORNEY GENERAL—RESIDENTIAL UTILITIES DIVISION

WITNESS:

ANDREW TWITE

February 7, 2022

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I. INTRODUCTION

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

A. My name is Mr. Andrew Twite. I am a rates analyst with the Office of the Minnesota Attorney General, Residential Utilities Division ("OAG"). My business address is 445 Minnesota Street, Suite 1400, St. Paul, MN 55101-2131.

Q. What is your educational and professional background?

A. My curriculum vitae is attached as Schedule AT-D-1. I have been with the OAG since November 2020, specializing in rate design, class cost of service, integrated resource planning, and resource acquisition. Prior to joining the OAG, I spent four years as a senior policy associate at Fresh Energy and three years as a rates analyst at the Minnesota Public Utilities Commission ("PUC" or "the Commission"), where I was the Commission's lead rate design staff-person on several general rate cases, including CenterPoint's 2015 rate case. I hold a master's degree in public policy and a bachelor's degree in political science, both from the University of Minnesota.

Q. How is your testimony organized?

A. In Section II, I discuss the Company's embedded class cost of service study ("CCOSS") and recommend modifications to better reflect underlying costs and benefits. I use the results of the modified CCOSS to inform my recommended class revenue apportionment, which is explained in Section III. In Section IV, I address the economic and policy implications of fixed monthly charges, provide customer-specific cost calculations, and recommend basic charge amounts for the Residential and Commercial A customer classes. Section V provides an overview of CenterPoint's historical construction costs, which have increased rapidly over the past twelve years. I discuss three of CenterPoint's distribution integrity management programs in Section VI and provide recommendations for test year costs and replacement timelines. In Section VII, I discuss CenterPoint's proposed Marketing Programs and recommend that these programs be rejected. Section VIII provides a summary of my recommendations.

II. CLASS COST OF SERVICE STUDY

Q. What is the purpose of this section of your testimony?

A. In this section, I discuss the Company's CCOSS.

Q. How is this section of your testimony organized?

A. I provide a general overview of the objectives of CCOSSes in subsection A. In subsections B through D, I highlight the three methods for classifying shared distribution system costs that have been considered in recent Minnesota rate cases: the Minimum System, Basic Customer, and Peak & Average methods. Ultimately, I conclude that the Peak & Average method is the most appropriate approach for classifying shared gas distribution infrastructure. In subsection E, I provide a survey of CCOSS approaches in neighboring states. In subsection F, I recommend modifications to the Company's embedded CCOSS to better reflect underlying costs and benefits. I use this updated CCOSS to inform my class revenue apportionment, which is addressed in Section III.

A. CLASS COST OF SERVICE STUDY BACKGROUND

Q. What are the basic components of an embedded CCOSS?

A. An embedded CCOSS is typically performed in three steps: functionalization, classification, and allocation. First, costs are "functionalized" into various categories that reflect the basic elements of the gas system, such as: production; transmission; distribution; billing and customer service; and administrative and general. In the second step, costs are classified according to the factors that drive the need for the cost, such as demand-related (a.k.a. capacity-related), commodity-related (a.k.a. energy-related), and customer-related. Finally, the cost categories are allocated to the various customer classes using specific parameters known as "allocation factors."

To enhance precision, these categories are often broken down into subcategories (e.g., sub-functions), and some costs can be directly assigned to specific customer classes (e.g., directly assigning the cost of the customer service department's large customer account representatives to a Large General Firm Sales class). Analysts can also enhance precision through the use of specific allocation factors. For example, if a utility's customer classes use different types of meters, rather than allocating meter costs based purely on the *number* of customers in each class, a utility could develop a specific meter allocation factor that reflects the weighted costs of the meters in service by class.

Q. What is the purpose of a CCOSS?

A. The purpose of a CCOSS is to inform a class revenue apportionment that equitably divides the costs of providing service among customer classes. However, "equity" is very subjective. Developing a CCOSS requires a multitude of subjective determinations and simplifying assumptions, many of which can dramatically impact the results of a study. Though some determinations are more reasonable than others, ultimately all CCOSSes are subjective, and there is not a universally accepted methodology for apportioning costs.

Q. What is an example of a subjective determination that significantly impacts the results of a CCOSS?

A. A primary example is the classification of shared distribution system costs, meaning the common infrastructure that is used by two or more customer classes. According to the Regulatory Assistance Project's ("RAP") 2020 Cost Allocation Manual, "The classification of distribution infrastructure has been one of the most controversial elements of utility cost allocation for more than a half-century."[1] Indeed, this issue has been hotly contested in several recent Minnesota rate cases.

Q. What are the most common methodologies for classifying distribution system costs?

A. In recent Minnesota rate cases, the three most commonly used methodologies have been the Minimum System, Basic Customer, and Peak & Average methods. I discuss each of these methods in more detail in subsections B through D, below.

Q. What has been the Commission's recent practice for classifying shared distribution system equipment costs?

A. The Commission's orders have varied from case to case, but the Commission's general practice in recent years has been to consider the results of all three methodologies.[2] For example, in CenterPoint's 2015 rate case the Commission concluded:

> The Commission does not concur with the Administrative Law Judge that the strengths of the minimum-system method are so superior to those of the other three analytical models developed in the record that they justify relying exclusively on a minimum-system analysis to classify and allocate distribution-system costs.
>
> . . .
>
> The Commission finds that the class-cost-of-service studies presented by the parties in this case are a useful guide to revenue apportionment and rate design

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[1] Jim Lazar et al., Regulatory Assistance Project, Electric Cost Allocation for a New Era: A Manual 145 (Jan. 2020).

[2] *See In the Matter of the Application of CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota*, G-008/GR-15-424, Findings of Fact, Conclusions, and Order at 53 (June 3, 2016); *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-017/GR-15-1033, Findings of Fact, Conclusions, and Order at 63 (May 1, 2017); *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, E-002/GR-15-826, Findings of Fact, Conclusions, and Order at 45 (June 12, 2017); *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota*, E-015/GR-16-664, Findings of Fact, Conclusions, and Order at 71 (Mar. 12, 2018); *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, G-011/GR-17-563, Findings of Fact, Conclusions, and Order at 33 (Dec. 26, 2018); *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, E-017/GR-20-719, Findings of Fact, Conclusions, and Order at 43-44 (Feb. 1, 2022).

> and will consider all the classification methods in making a revenue-apportionment decision.
>
> The OAG showed that there are several methods, including the minimum-system, basic-customer, and peak-and-average methods, for classifying and allocating distribution-system costs. The Commission finds merit in each theory.[3]

Q. What approach has CenterPoint taken in this rate case?

A. CenterPoint's CCOSS witness—Ralph Zarumba—considered only the Minimum System method.

Q. Do you agree with Mr. Zarumba's approach?

A. No. The Minimum System approach is the least reasonable of the three methodologies. As explained in subsection B, below, the Minimum System method is theoretically flawed, and there are additional computational flaws in Mr. Zarumba's application of the method.

Q. What is your preferred approach for classifying shared distribution system infrastructure?

A. For gas utilities, I believe the Peak & Average is the most appropriate method, for the reasons outlined in subsection D. However, I believe the Commission's approach—i.e., considering the results of all three methods—is also reasonable.

B. THE MINIMUM SYSTEM METHOD

Q. What is the Minimum System method?

A. The Minimum System method is a CCOSS approach that classifies the costs of the shared distribution system as customer- and demand-related. The method is founded upon the belief that a utility would incur costs to install a distribution system even if the system served little or no load. The costs of a hypothetical minimum-sized distribution system are

[3] *In the Matter of the Application of CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota*, G-008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 53 (June 3, 2016).

estimated and compared to the costs of the actual distribution system; the costs of the minimum-sized system are classified as customer-related and the remainder is classified as demand-related. The hypothetical minimum system can be estimated in several ways, including the Minimum Size method and the Zero Intercept method.

Q. What is Mr. Zarumba's rationale for using the Minimum System method in CenterPoint's CCOCSS?

A. Mr. Zarumba explains his reasoning for using the Minimum System approach on pages 31–33 of his direct testimony. According to Mr. Zarumba:

> Two cost factors influence the level of distribution main facilities installed by a gas utility in expanding its gas distribution system. First, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid over time to connect new customers to the system. Second, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the coincident peak gas demand placed on the gas utility's system by its firm customers. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment and the related operation and maintenance ("O&M") expenses based on both the number of customers served by the gas utility and its design day demands.[4]

Q. Do you agree with Mr. Zarumba's logic?

A. No. Mr. Zarumba's argument has a fatal flaw: the Company's decision to expand its distribution system is not based on the *number of customers* served, but on the *expected revenues* from the prospective new customers. According to the CenterPoint's Minnesota Rate Book, "In determining whether [extension of a distribution main to serve a new customer] is economically feasible, CenterPoint Energy shall take into consideration the total cost of serving the applicant and the *expected revenue* from the applicant."[5]

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[4] Zarumba Direct at 31.
[5] CenterPoint Energy Gas Rate Book at Section VI, Fourth Revised Page 4 (June 1, 2021) (emphasis added), *available at* https://www.centerpointenergy.com/en-us/Documents/RatesandTariffs/Minnesota/CPE-MN-Tariff-Book.pdf.

Prospective new customer revenues are primarily a function of their energy consumption; if the prospective customer had little to no usage—as the Minimum System calculation assumes—the Company would not extend the distribution system to serve the customer in the first place. In addition to gas main extensions, the Company has a similar policy for service lines.[6]

Thus, Mr. Zarumba's statement would be more accurately phrased as: the total installed footage of distribution mains is primarily influenced by the *energy usage* of new customers. In CCOSS terms, total installed footage is better understood as commodity-related than customer-related.

Q. Did Mr. Zarumba provide an illustrative example to support his use of the Minimum System method?

A. Yes. On pages 32–33 of his direct testimony, Mr. Zarumba detailed the steps involved in extending gas service to a new residential subdivision. Mr. Zarumba argues that many of the steps are necessary regardless of the amount of expected gas consumption, and that "a large percentage of the costs of providing gas delivery service to a gas utility's customers are incurred before they ever use one unit of gas."[7]

Q. What is your response to Mr. Zarumba's example?

A. The passage is a good illustration of the main extension process and is worth reading in full. However, Mr. Zarumba's conclusion is founded on the same fallacy noted above: the Company would only expand its service area to serve the new subdivision if it projected that the new revenues would justify the expansion. And, since revenues are primarily a

[6] *See id.* at Section VI, Third Revised Page 11 ("CenterPoint Energy may install gas service lines without charge to service applicants *where the anticipated revenues are sufficient to warrant such installation* or in other cases where CenterPoint Energy determines the conditions justify such installation." (emphasis added)).
[7] Zarumba Direct at 33.

function of energy consumption, the subdivision expansion was driven primarily by the amount of commodity sales, not the number of new customers served.

Adding detail to Mr. Zarumba's example helps illustrate why distribution costs are better understood as commodity-related than customer-related. According to the NARUC Gas Manual, customer-related costs are those that "vary directly with the number of customers served rather than with the amount of utility service supplied."[8] Using Mr. Zarumba's residential subdivision example, compare a new residential development with ten single-family homes to one with ten duplexes in the same geographic configuration and with the same cumulative gas usage. The distribution main installation costs detailed by Mr. Zarumba would be the same for both developments, even though the number of customers would be twice as large for the duplex development. Similarly, the shared distribution costs to serve a single commercial building would be the same if there were one large tenant or twenty smaller offices, provided the usage was the same.

Thus, shared distribution costs are less a function of the number of customers than of the physical layout of the service area and its cumulative usage and peak demand.

Q. Is it appropriate to classify any distribution system costs as customer-related?

A. Yes, it is appropriate to classify customer-specific distribution system costs as customer-related. In the example above, the duplex development would require twice as many meters as the single-family development; it is appropriate to classify these meters as customer-related. Similarly, the costs to connect the buildings to the shared distribution system—service lines, regulators, etc.—are reasonably considered customer-related.[9]

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[8] NAT'L ASS'N OF REGULATORY UTILITY COMM'RS, GAS DISTRIBUTION RATE DESIGN MANUAL 22 (1989).

[9] Because service lines are also sized to meet the peak demand, it would also be appropriate to classify a portion of their costs as demand-related.

Q. Do you have additional concerns with Mr. Zarumba's Minimum System Study?

A. Yes. In addition to the theoretical flaws of the Minimum System approach, Mr. Zarumba's Minimum System Study also has two significant computational flaws. In his defense of the Minimum System approach, Mr. Zarumba stated:

> [T]he customer component of distribution mains is premised upon the concept of a "minimum system." The "minimum system" for a gas distribution utility is the *smallest hypothetical system* a gas utility would construct to connect its customers.[10]

However, when he performed his Minimum System study, Mr. Zarumba did not calculate the "smallest hypothetical system," but instead calculated the cost of a system with the *most commonly installed* pipe size and material, namely a two-inch plastic or steel main.[11]

Mr. Zarumba's modification of the Minimum System method is problematic for two reasons. First, two inches is not the smallest size of pipe currently installed in CenterPoint's distribution system; nine percent of the Company's current distribution system is made up of pipes with a 1.25 inch diameter or less, with individual mains as small as 0.5 inches in diameter.[12] Second, Mr. Zarumba's calculation assumes the "minimum system" would include the same mix of plastic and steel pipes as CenterPoint's existing system. Steel pipes are more expensive than plastic, and are used when the pressure demands on the line necessitate the additional strength provided by steel. However, because the "smallest hypothetical system" would have little to no load, the minimum system serving this load would use only plastic mains.

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[10] Zarumba Direct at 31 (emphasis added).

[11] On page seven of his direct testimony, Mr. Zarumba claims, "The two-inch main was chosen because it is the minimum-sized distribution main currently used by the company." This is erroneous. According to Mr. Zarumba's own Minimum System study, in 2020 the Company installed mains of 1.5-, 1.25-, 1-, 0.75-, and 0.5-inch diameters.

[12] Zarumba Workpaper 1 at 36.

Q. How do these computational flaws impact Mr. Zarumba's estimate of Minimum System costs?

A. Each of these methodological choices increase the cost of the hypothetical Minimum System. Under Mr. Zarumba's two-inch Minimum System study, the average cost per foot for distribution mains is $16.37.[13] For comparison, the average cost of a one-inch plastic pipe in CenterPoint's system is $5.56/foot, or roughly one-third the cost of Mr. Zarumba's "minimum system."[14]

Q. Did Mr. Zarumba modify the results of his two-inch Minimum System study before classifying shared distribution system costs?

A. Yes. The two-inch plastic and steel mains used in Mr. Zarumba's calculation have significant capacity-carrying capability; in fact, nearly two-thirds of CenterPoint's currently installed distribution main footage consists of two-inch or smaller pipe.[15] Accordingly, CenterPoint adjusted the results of its two-inch Minimum System study in an attempt to account for the carrying capacity of the pipe, which reduced the amount classified as customer-related.[16]

Q. Does this adjustment correct the computational flaws highlighted above?

A. No. Even after the adjustment, the distribution main cost in Mr. Zarumba's Minimum System study was $11.29/foot, which is still double the average (actual) installed cost of the one-inch plastic distribution mains on CenterPoint's system.

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[13] Zarumba Workpaper 1 at 36. Total 2" Customer Cost ($1,248,963,750) divided by Installed Footage (76,296,225) equals $16.37/foot.

[14] CenterPoint's response to DOC IR 706, attach. 1. This number differs from the one-inch plastic cost/foot included in Zarumba Workpaper 1, page 36. As the Company explained in its response to OAG IR 7010, it "determined that a limited number of data points should be eliminated from the data set because they were either unrepresentative or erroneous." The cited figure is the average cost/foot for one-inch plastic pipes excluding the "unrepresentative or erroneous" observations.

[15] Zarumba Workpaper 1 at 36.

[16] The adjustment methodology is described on pages 35–36 of Mr. Zarumba's direct testimony.

Q. Did Mr. Zarumba calculate Minimum System costs using another methodology?

A. Yes. As mentioned above, there are two common approaches for estimating Minimum System costs: the Minimum Size method and the Zero Intercept method. Mr. Zarumba's two-inch Minimum System Study is a modification of the Minimum Size method. In addition, Mr. Zarumba also performed a Zero Intercept study.[17]

Q. Did Mr. Zarumba use his Zero Intercept calculation in his CCOSS?

A. No. The Company did not include the Zero Intercept study in its filing; Mr. Zarumba believes the results of the Zero Intercept study were "anomalous" because they resulted "in a higher customer-related percentage than the minimum system study."[18]

Q. Do you agree with Mr. Zarumba's characterization of the Zero Intercept study?

A. No. The results of the Zero Intercept study are only anomalous for steel mains. The Zero Intercept estimate of plastic main costs—$2.43/foot—is below the cost of the least-cost mains on CenterPoint's system and is consistent with the theory underlying the Zero Intercept approach. And, as noted above, plastic pipe would be sufficient to serve the "smallest hypothetical system."

Thus, if one believed it was reasonable to consider the Minimum System method at all, it would be appropriate to consider the results of both the Minimum Size and Zero Intercept methods.

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[17] For more detail on the Zero Intercept approach, see NAT'L ASS'N OF REGULATORY UTILITY COMM'RS, ELECTRIC UTILITY COST ALLOCATION MANUAL 92–95 (1992).

[18] CenterPoint's response to OAG IR 7011.

Q. Will you please summarize the results of the different Minimum System approaches discussed above?

A. Yes. Figure 1 compares the classifications that result from CenterPoint's adjusted and unadjusted two-inch Minimum System calculation, a one-inch plastic Minimum System, and the Zero Intercept method.

Figure 1, Comparison of Minimum System method results

	CPE 2" Min Sys Unadjusted	CPE 2" Min Sys Adjusted	1" Plastic Min Sys	Zero Intercept (Plastic)
Customer-related	42%	29%	14%	6%
Demand-related	58%	71%	86%	94%

Q. What do you conclude from Figure 1?

A. There are at least two noteworthy features of these results. First, even after the adjustment, Mr. Zarumba's Minimum System calculations classify twice as many costs as customer-related than the one-inch plastic Minimum System method, and nearly five times more than the Zero Intercept Method.

Second, there is considerable variation in the results, even though all four of these studies are versions of the Minimum System approach. One of the main weaknesses of the Minimum System approach is that it is purely hypothetical; it attempts to estimate the cost of a system that has never been, and would never be, built. This necessitates a number of subjective determinations, which can dramatically alter the results, as illustrated above.

Q. What do you conclude regarding Mr. Zarumba's two-inch Minimum System Study?

A. The Minimum System method is theoretically flawed. The Company's decision to expand its service area is driven by expected revenues, which are primarily a function of usage. Once a company decides to expand its service area, the actual pipe size and material is determined based on the expected peak demands. Thus, shared distribution system costs are better understood as commodity- and demand-related. Moreover, even if the Minimum System approach were theoretically sound, the methodological flaws in Mr. Zarumba's Minimum System Study result in a significant overestimation of the cost of the smallest hypothetical system.

In light of the theoretical and computational issues with Mr. Zarumba's Minimum System study, I do not believe it should be considered in class revenue apportionment.

C. The Basic Customer Method

Q. What is the Basic Customer method?

A. The Basic Customer method is a CCOSS approach that classifies the costs of the shared distribution system entirely as demand-related. Under this approach, distribution equipment that serves a single customer (or a single multi-use building) is classified as customer-related and all shared distribution equipment is classified as demand-related. Shared distribution system costs are classified as demand-related in recognition of the fact that the distribution system is designed primarily to reliably serve the cumulative demand of the customers on the system.

Q. What is the main strength of the Basic Customer method?

A. The Basic Customer method is the approach that most closely corresponds to the way in which engineers design gas distribution systems. Once the decision is made to expand into a new service area, the size and material of the mains other distribution equipment is chosen to ensure the Company will be able to provide reliable service throughout the year. This typically means the equipment is sized to be able to meet coincident peak—i.e., design day—demand. As Mr. Zarumba put it, "From a gas engineering perspective, it is clear that a design day demand criteria is always utilized when designing a gas distribution system."[19]

Q. What is the main weakness of the Basic Customer method?

A. If demand-related costs are allocated based purely on coincident-peak demand, as in CenterPoint's CCOSS, then the main weakness of the Basic Customer method is that it does not account for the energy-related portion of distribution system costs. As explained above, the decision to build a distribution system is based on expected revenues, which are primarily a function of usage. In other words, if there were no usage, the distribution system would not exist in the first place. Moreover, even if there were no peak demand—i.e., if usage were perfectly constant every hour of the year—a distribution system would still need to be constructed; this distribution system would use smaller components and have a lower total cost than the system that actually exists, but it would be necessary nonetheless.

Q. What do you conclude regarding the Basic Customer method?

A. The Basic Customer method has considerable pragmatic appeal, as it is the method that most closely corresponds with the actual design criteria used by engineers in designing distribution systems. However, it is less appealing theoretically, as it does not account for the fact that the existence of the gas distribution system is primarily the result of energy usage and that a distribution system would be necessary even if usage were flat throughout the year. Thus, I believe the Basic Customer method is more reasonable than the Minimum System method, but less reasonable than the Peak & Average method for gas utilities.

[19] Zarumba Direct at 22.

D. THE PEAK & AVERAGE METHOD

Q. What is the Peak & Average method?

A. The Peak & Average method is a CCOSS approach that classifies the costs of the shared distribution system as demand- and energy-related. This approach acknowledges that a portion of the shared distribution system is needed to serve a regular amount of energy usage at all times, while additional costs are incurred to ensure the network can meet the cumulative local peak demand. In other words, the distribution system would need to be sized to serve customers' energy consumption even if usage was perfectly flat throughout the year—i.e., if there were no peak demand.

The Peak & Average method classifies a portion of shared distribution system costs as energy-related—to reflect the baseline energy needs of the system—and the remainder as demand-related—to reflect the "upsizing" of the system to be able to meet peak demand. Typically, the basis for the energy-related portion is the Company's load factor, or the ratio of average usage to peak demand.

Q. Does Mr. Zarumba support the use of the Peak & Average method in this case?

A. No. Though Mr. Zarumba does not mention the Peak & Average method by name, he does discuss the underlying concepts in his discussion of the allocation of peak demand costs.[20] For example, Mr. Zarumba argues:

> In reality, customers require design day capacity when needed even though it is not fully utilized, except under design day conditions, because of the importance of service reliability under those operating and load conditions. Once capacity is available to serve the design day, commodity use during all other days of the year has no impact on a utility's demand-related costs.[21]

[20] *Id.* at 26–29.
[21] *Id.* at 27.

Q. What is your response to this argument?

A. For the most part I agree with this argument, though I would note it is a justification for the Basic Customer approach, not Mr. Zarumba's preferred Minimum System approach. However, this argument ignores the fact that it is usage that causes the distribution system to constructed in the first place, and that a distribution system would be necessary to provide average usage even if there were no peak demand.

In order to truly reflect cost causation, one must consider not just the system as it exists at a single point in time, but the history of the system—why it was constructed the way it was and why it even exists in the first place.

Q. What is your conclusion regarding the Peak & Average method?

A. I believe the Peak & Average is the most reasonable method for classifying shared gas distribution system costs. The Peak & Average method provides the best balance of pragmatic and theoretical considerations; the majority of costs are classified as demand-related to account for the fact that the system is designed to reliably serve peak demand, but a portion of costs are classified as commodity-related to acknowledge that gas distribution systems—indeed, gas utilities as a whole—exist to serve customers' commodity usage.

E. CLASS COST OF SERVICE STUDIES IN THE UPPER MIDWEST

Q. Did you perform a survey of distribution main classification in neighboring jurisdictions?

A. Yes. In CenterPoint's 2015 rate case, the Company's CCOSS witness—Russel Feingold—provided a survey of cost classification and allocation of distribution mains in other jurisdictions.[22] I found this survey helpful at the time, but as it is beginning to show its age, I decided to update the survey. In the interest of time, I narrowed my review to states in the Upper Midwest.[23] My survey identified the method(s) the utilities used to classify and allocate distribution system costs. Because a large majority of the rate cases I surveyed ended up settling, there were relatively few direct discussions of CCOSS methods in commission orders; accordingly, I also reviewed the commission staff's CCOSS testimony in each case. The survey is included as Schedule AT-D-2.

Q. Did you identify any patterns in your survey?

A. Given the debate surrounding this topic in recent Minnesota rate cases, I had expected to find a wide variation in the techniques used in these states. However, while no two states do things exactly alike, I observed three clear patterns in my review.

First, in most of these cases, distribution main costs were classified/allocated[24] as demand- and commodity-related, even in the utility's preferred CCOSS. For example, in nearly all of the recent gas rate cases in Illinois, Iowa, Michigan, and South Dakota distribution mains were classified as demand- and commodity-related.

Second, classification of main costs as customer-related was uncommon. Further, even those utilities that classified a portion of main costs as customer-related typically also classified a portion as commodity-related. For example, in Wisconsin the common practice in gas cases is to consider the results of two CCOSSes, one that classifies costs as demand-

[22] *See In the Matter of the Application of CenterPoint Energy Corp. for Authority to Increase Natural Gas Rates in Minnesota,* Docket No. G-008/GR-15-424, Rebuttal Testimony of Russell A. Feingold, sched. 3 (Dec. 18, 2015).

[23] Specifically, I reviewed dockets in Illinois, Iowa, Michigan, North Dakota, South Dakota, and Wisconsin. For the more populous states, I limited my review to the larger gas utilities in the state.

[24] In some cases, main costs were classified as 100 percent demand-related but then allocated using a weighted commodity and demand allocator. For simplicity, in this section I refer to this practice simply as "classifying as demand- and commodity related," since the net result of this approach is the same as classifying costs as demand- and commodity-related and allocating using separate energy and demand allocators.

and commodity-related, and another that classifies costs as demand-, commodity-, and customer-related. Similarly, in North Dakota—which was the only state in which utilities consistently used only the Minimum System method—most of the utility CCOSSes also classified a portion of main costs as commodity-related.

Third, in the few instances in which utilities recommended sole use of the Minimum System method, commission staff often explicitly opposed the use of the Minimum System method and recommended another approach. In fact, in the 19 gas rate cases I reviewed, I did not find a single instance in which commission staff approved of the approach Mr. Zarumba is recommending in this case.[25]

Q. What do you conclude based on this survey?

A. Mr. Zarumba's proposed approach—i.e., classifying main costs solely as demand- and customer-related—appears to be rare among Upper Midwest gas utilities.[26] Conversely, my proposed approach—i.e., classifying main costs as demand- and commodity-related—appears to be the most common approach in these states.

Q. Are there any qualifications to your survey?

A. Yes, I did not participate in any of these rate cases. I simply reviewed the testimony in the docket records for the rate cases I could locate on the states' websites. If any party believes I misinterpreted any of these filings or omitted relevant rate cases, I request that it identify any errors and/or docket numbers for additional cases in rebuttal testimony.

[25] Namely, considering only the Minimum System method and not classifying any portion of distribution mains as commodity-related.

[26] The utility took this approach in just 2 of the 19 gas rate cases I reviewed.

F. CLASS COST OF SERVICE STUDY RECOMMENDATIONS

Q. What is your recommendation regarding classification of shared distribution system costs in this case?

A. In light of the evidence provided above, I recommend that shared distribution system costs be classified using the Peak & Average methodology.

Q. Do you have an additional recommendation regarding CenterPoint's CCOSS?

A. Yes. I also take issue with the way CenterPoint calculated its service line allocation factor. Specifically, there are two problems with CenterPoint's allocator. First, the calculation uses inconsistent time periods for the customer classes: it uses the average of the last two years of historical costs for some classes and the average of the last six years of historical costs for others. This is especially problematic in light of the significant cost inflation for service lines outlined in Section V, below.

Second, in its weighted service line cost calculation, the Company uses the number of customer *meters*, rather than the actual number of service lines. This is inappropriate because a single service line can serve many customer meters. For example, CenterPoint provides service to an apartment building in Edina that has 185 meters all served by a single service line.[27] The Department has identified this problem in at least CenterPoint's last two rate cases, yet the Company has continued its practice in this case.[28] Further, a single service line can also serve multiple customer classes; CenterPoint noted that it has many service lines that provide service to both Residential and Commercial customers.[29]

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[27] CenterPoint's response to OAG IR 7009(C).
[28] *See* Docket No. G-008/GR-19-524, Direct Testimony of Adam J. Heinen at 58–59 (July 15, 2020); Docket No. G-008/GR-17-285, Direct Testimony of Danielle D. Winner at 39–48 (Jan. 8, 2018).
[29] CenterPoint's response to OAG IR 7009(B). The Company lists 1,395 specific service lines, but this number likely significantly underestimates the total amount of shared service lines, as the Company notes that "many service line and meter equipment records are not tied to one another" in its system, "especially in multiple meter situations."

To address these issues, I updated CenterPoint's service line allocator to use consistent time periods for all classes and to use the actual number of service lines serving each class. I also attempted to correct for the number of service lines that are shared by multiple customer classes, but this correction likely underestimates the number of shared service lines in CenterPoint's system.[30]

Q. Has CenterPoint provided an updated CCOSS reflecting your recommendations?

A. Yes, CenterPoint has provided a CCOSS using the Peak & Average method to classify distribution system costs and that uses my revised service line allocator. This CCOSS is the basis for my class revenue apportionment, which is described in the next section of my testimony. Further, in recognition of the Commission's preference for consideration of multiple CCOSSes, I also asked CenterPoint to provide two additional CCOSSes: one using my revised service line allocator and the Basic Customer method to classify distribution system costs; and a second using my revised service line allocator and a one-inch plastic Minimum System study to classify distribution system costs. Figure 2, below, summarizes the results of each of these three CCOSSes.

Q. Do you make any recommendations regarding CCOSS for CenterPoint's next rate case?

A. Yes. In light of the Commission's preference in recent rate cases, I recommend CenterPoint file Peak & Average and Basic Customer CCOSSes in the initial filing of its next rate case.

[30] *Id.*

III. CLASS REVENUE APPORTIONMENT

Q. What is the purpose of this section of your testimony?

A. In this section, I provide my recommended class revenue apportionment.

Q. How is this section of your testimony organized?

A. In subsection A, I give an overview of class revenue apportionment and identify relevant policy considerations. I explain my apportionment methodology in subsection B, and I provide my recommended class revenue apportionment in subsection C.

A. CLASS REVENUE APPORTIONMENT BACKGROUND

Q. What CCOSS methodologies inform your recommended revenue apportionment?

A. My recommended class revenue apportionment is founded upon my preferred Peak & Average CCOSS as described in Section II.F, above. In keeping with recent Commission practice, I also consider the results of the Basic Customer and Minimum System studies discussed above.

Q. What are the results of the three CCOSS methods?

A. Figure 2 compares CenterPoint's current revenue apportionment with the revenue apportionments that would result from a full movement to cost as defined by each of the three CCOSS methods.[31]

[31] Compiled by the author using the results of the modified CCOSSes provided by the Company in its response to OAG IRs 7014 (Peak & Average), 7015 (Basic Customer), and 7016 (one-inch plastic Minimum System).

Figure 2, Class revenue apportionment by CCOSS method

Customer class	Current apportionment	Peak & Average	Basic Customer	Minimum System
Residential	64.4%	53.2%	58.4%	61.1%
C&I A	2.6%	2.5%	2.8%	3.3%
C&I B	4.1%	4.1%	4.8%	4.7%
C&I C - Sales	17.6%	18.1%	19.9%	18.3%
C&I C - Transport	0.5%	0.9%	0.4%	0.4%
Small Dual Fuel - A - Sales	1.4%	1.7%	0.8%	0.7%
Small Dual Fuel - A - Transport	0.1%	0.1%	0.1%	0.1%
Small Dual Fuel - B - Sales	0.8%	1.0%	0.5%	0.4%
Small Dual Fuel - B - Transport	0.2%	0.2%	0.1%	0.1%
Large Firm - Sales	0.4%	0.5%	0.5%	0.4%
Large Firm - Transport	3.5%	8.0%	6.6%	5.8%
Lg Dual Fuel Sales	1.6%	2.8%	1.9%	1.7%
Lg Dual Fuel Transport	2.7%	6.9%	3.3%	3.0%

Q. Is your recommended revenue apportionment based solely on cost of service?

A. No. Though my preferred CCOSS is the foundation of my recommendation, it is important to consider state policy in class revenue apportionment.

Q. Why is it important to consider policy in revenue apportionment?

A. A rate case is a two-step process: the Commission first establishes the revenue requirement, acting in its quasi-judicial capacity as a factfinder; in the second step, rate design, the Commission determines how recovery of the revenue requirement is allocated between classes and how rates are structured within classes.[32] In this second step, the Commission exercises its legislative function, which requires "balancing both cost and non-cost factors and making choices among public policy alternatives" to determine the revenue apportionment and rate structure that are most consistent with the public interest.[33]

[32] *Hibbing Taconite Co. v. Minnesota Pub. Serv. Comm'n*, 302 N.W.2d 5, 9 (Minn. 1980).
[33] *St. Paul Area Chamber of Commerce v. Minnesota Pub. Serv. Comm'n*, 251 N.W.2d 350, 358 (Minn. 1977).

Q. What is an example of a policy consideration that informs your revenue apportionment recommendation?

A. One important policy consideration for revenue apportionment is "gradualism." In many cases, setting class revenue apportionment exactly at the cost of service as measured by a single CCOSS would necessitate dramatic rate increases for some classes. For example, if the Commission were to set the class revenue apportionment precisely at the cost levels determined by CenterPoint's Minimum System CCOSS, it would result in a sixty percent rate increase for the Large Firm – Transport class. This dramatic increase would likely cause rate shock for customers in this class. To avoid this result, it is important for policy makers to adjust rates gradually, to move classes closer to cost while also moderating the rate increase for any single class.

B. CLASS REVENUE APPORTIONMENT METHODOLOGY

Q. What methodology did you use to develop your recommended revenue apportionment?

A. I used a three-step methodology to develop my recommendation. In the first step, I compared the current class revenue apportionment to the results of my preferred CCOSS. Two classes—the Residential and Commercial & Industrial ("C&I") A—are currently paying more than their cost of service, and the C&I B class is currently paying almost its exact cost of service. All other classes are currently paying less than their cost of service.

In the second step, I compared the current class revenue apportionment to the results of the Basic Customer and one-inch plastic Minimum System studies. The Residential class is currently paying more than its cost of service according to all three methodologies, and five classes—C&I C Sales, Large Firm Sales & Transportation, and Large Dual Fuel Sales & Transportation—are paying less than their cost of service according to all three methodologies. For the remaining classes, whether they are paying more or less than their share of costs depends on the CCOSS method being used.

Finally, in the third step I designated a specific rate increase for each class. The rate increase is based largely on the magnitude of the difference between the amount the class is currently paying and its cost of service in my preferred CCOSS, but it also takes the results of the other two CCOSS methodologies into account. Further, I limited the percentage increase to a maximum of 25 percent to avoid rate shock.[34] The specific class increases were determined as follows:

- The Residential and C&I A classes received the smallest increases because these classes are both currently paying more than their fair share of costs;
- The C&I B class is currently paying almost exactly its cost of service, so this class's increase was set at the Total Company average rate increase (6.5 percent);
- The C&I C – Sales class is currently paying slightly less than its cost of service, so this class received a slightly larger increase than the Total Company average;
- Five classes—C&I C – Transportation and all four Small Dual Fuel classes—are paying less than their share of costs according to the Peak & Average CCOSS, but more than their share of costs according to the other two methods, and so received increases moderately larger than the Total Company average;
- The Large Firm and the Large Dual Fuel classes are all currently paying well below their cost of service in each of the three CCOSS methods, and so received the largest increases.

[34] Even a 25 percent increase may still be large enough to result in rate shock. However, it is my expectation that the final approved Total Company rate increase will be smaller than that requested by the Company, and so these amounts will be adjusted downward using the formula provided in the following subsection.

C. Class Revenue Apportionment Recommendation

Q. What is your recommended class revenue apportionment?

A. Figure 3 displays current class revenues and my recommended class revenue apportionment at the Company's proposed revenue requirement.

Figure 3, OAG recommended class revenue apportionment

Customer class	Current revenues	OAG proposed revenues	Increase $	Increase %
Residential	$617,781,801	$643,147,377	$25,365,575	4.1%
C&I A	$21,728,210	$22,975,409	$1,247,199	5.7%
C&I B	$46,493,164	$49,533,817	$3,040,653	6.5%
C&I C - Sales	$244,293,398	$264,178,881	$19,885,483	8.1%
C&I C - Transport	$2,217,722	$2,512,679	$294,957	13.3%
Small Dual Fuel - A - Sales	$19,887,341	$22,134,611	$2,247,270	11.3%
Small Dual Fuel - A - Transport	$556,172	$610,343	$54,171	9.7%
Small Dual Fuel - B - Sales	$12,630,817	$14,108,623	$1,477,806	11.7%
Small Dual Fuel - B - Transport	$658,363	$723,804	$65,441	9.9%
Large Firm - Sales	$6,067,880	$7,020,537	$952,657	15.7%
Large Firm - Transport	$15,421,383	$19,261,307	$3,839,924	24.9%
Lg Dual Fuel Sales	$30,274,827	$36,299,518	$6,024,691	19.9%
Lg Dual Fuel Transport	$11,930,995	$14,500,931	$2,569,936	21.5%
Company Total	$1,029,942,074	$1,097,007,837	$67,065,763	6.5%

Q. Why do you recommend this apportionment?

A. My recommended apportionment moves classes closer to cost while moderating movements to account for patterns in the three CCOSS models and to avoid rate shock.

Q. How should the Commission allocate the rate case increase if it authorizes a lower revenue increase than the $67 million requested by the Company?

A. The specific class increases in Figure 3 were set at levels necessary to meet Company's full requested revenue increase. If the final approved revenue requirement is lower than the amount requested by CenterPoint, I recommend the final class increases be determined by multiplying the PUC's approved Total Company revenue increase by the ratio of the OAG's recommended class increase to CPE's proposed Total Company increase.[35]

IV. RESIDENTIAL AND COMMERCIAL A MONTHLY BASIC CHARGES

Q. What is the purpose of this section of your testimony?

A. In this section, I discuss the Company's proposal to increase Residential and Commercial A monthly basic charges.

Q. How is this section of your testimony organized?

A. Subsection A describes CenterPoint's proposed basic charge increases for Residential and Commercial A customers. In subsection B, I calculate customer-specific costs for these classes, which are the costs that are appropriate to collect through a fixed charge. Subsection C details relevant fixed-charge policy considerations. I respond to the Company's arguments in support of its proposed increases in subsection D. Finally, subsection E provides my basic charge recommendations.

A. CENTERPOINT'S PROPOSED BASIC CHARGES

Q. What are the Company's basic charges?

A. CenterPoint's monthly basic charge is a fixed amount all customers in a given class must pay each month, regardless of the amount of natural gas consumed. This type of monthly fee is also referred to as a "fixed fee" or a "customer charge." Customer charges are intended to collect the costs of providing gas service that are specific to individual customers and that do not vary with energy usage or peak demand. CenterPoint's basic

[35] For example, the OAG's recommended increase for the C&I C – Sales class (8.1 percent) is 25 percent larger than CenterPoint's proposed Total Company increase (6.5 percent). If the PUC's final Total Company approved revenue increase were 3 percent, the C&I C – Sales class's adjusted increase would be 3.7 percent (8.1% / 6.5% x 3% = 3.7%).

charges are in addition to the amount customers pay per therm of gas consumed, which I refer to below as "volumetric rates."

Currently, the Company's basic charge is $9.50 per month ($114/year) for Residential customers and $15 per month ($180/year) for Commercial A customers.

Q. How is the Company proposing to change its monthly basic charges in this rate case?

A. The Company proposes to increase the Residential basic charge to $11 per month ($132/year), or an increase of 16 percent. For Commercial A customers, the Company proposes increasing the basic charge to $17.50 per month ($210/year), which would be a 17 percent increase. For these classes, the Company's proposed customer charge increases are significantly larger than its proposed overall revenue increase of 6.5 percent.

The Company's rate design proposals for these customer classes are described on pages 61–68 of Mr. Zarumba's direct testimony.

Q. What reasons did the Company provide for increasing its basic charges?

A. The Company provided several justifications for its proposed increases, which are described in subsection D, below. As explained in that section, the stated justifications do not warrant CenterPoint's proposed basic charge increases.

B. Customer-Specific Cost Calculation

Q. What costs are appropriate to include in a fixed monthly charge?

A. In his seminal work on rate design, economist James Bonbright stated, "There are those operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption. Included as a minimum are the costs of metering and billing along with whatever other expenses the company must incur in taking on another customer."[36]

Another widely cited utility rate design text, *Economics of Regulation: Principles and Institutions* by Alfred Kahn concluded that fixed fees "reflect the costs of services such as meter-reading and billing that vary on a per customer basis instead of with different amounts purchased."[37]

A more recent example comes from a paper by University of California-Berkeley Economics Professor Severin Borenstein:

> The variety of fixed costs that a utility incurs raises a distinction between customer-specific fixed costs and systemwide fixed costs. Customer-specific fixed costs vary according to whether the customer receives service from the utility, regardless of [their volumetric usage]. These include incremental metering and billing costs for that customer, and maintaining the connection from the distribution system to the customer's meter. Systemwide fixed costs cannot be attributed to a specific customer and are independent of the [energy] consumed on the system. These include construction and maintenance of the local distribution networks, the corporate structure and public purpose programs, such as energy efficiency and distributed generation programs. The distinction has particularly important implications for discussions of equity or cost causality.[38]

Taken together, these and other[39] rate design texts conclude that a calculation of customer-specific costs for a gas utility should include, at maximum: service lines (i.e., the

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[36] JAMES C. BONBRIGHT, PRINCIPLES OF PUBLIC UTILITY RATES 347 (1st ed. 1961)

[37] ALFRED KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS 95 (1988).

[38] Severin Borenstein, *The Economics of Fixed Cost Recovery by Utilities* at 7 (Univ. of California, Berkeley, Haas Sch. of Bus. Energy Inst. Working Paper No. 272R, July 2016). The original quote refers to electricity usage, but the underlying concept is the same for gas usage.

[39] *See, e.g.*, JIM LAZAR AND WILSON GONZALEZ, REGULATORY ASSISTANCE PROJECT, SMART RATE DESIGN FOR A SMART FUTURE 36 (July 2015) ("The fixed charge for residential or commercial service should not exceed the customer-specific costs attributable to an incremental consumer. For urban and suburban residential consumers, this is the cost of a service drop, the portion of the meter cost directly related to billing for usage, plus the cost of periodic (monthly, bimonthly, or quarterly) billing and collection."); MELISSA WHITED ET AL., SYNAPSE ENERGY ECONOMICS, CAUGHT IN A FIX: THE PROBLEM WITH FIXED CHARGES FOR ELECTRICITY 24 (Feb. 9, 2016) ("Where it is used at all, the customer (fixed) charge should be limited to only recovering costs that vary directly with the number of customers, such as the cost of the meter, service drop, and customer billing, as has traditionally been done.").

connection to the shared distribution system), meters and house regulators, meter reading, and billing costs.

Q. Have you calculated the test year customer-specific costs for CenterPoint's Residential and Commercial A customers?

A. Yes, my customer-specific cost calculations for these customer classes are attached as Schedule AT-D-3, below, and the results are summarized in Figure 4, below.

Q. What costs do you include in your customer-specific cost calculation?

A. My calculation includes each of the components outlined above, namely:

- Service lines (FERC accounts 380, 874, and 892);
- Meters and house regulators (FERC accounts 381, 382, 383, 878, 879, and 893);
- Meter reading (FERC account 902); and
- Customer records and collection (FERC account 903).

For physical infrastructure, my calculation includes depreciation expense, the Company's grossed-up return on net plant in service, and operations and maintenance ("O&M") expenses.

Q. Do you calculate both maximum and minimum customer-specific cost amounts?

A. Yes. There are three factors that differ between my maximum and minimum calculations:

- The first difference relates to service line expenses (FERC account 874). This account includes the combined total of expenses for both mains and service lines, and service lines make up a small amount of the total costs in these accounts. Since it is not possible to isolate the service line component of these accounts, in the maximum calculation I estimated service line O&M expenses for each account using the proportion of net plant in service for FERC accounts 376 and 380.[40] Acknowledging this approach is not ideal and may overstate service line expenses, my minimum calculation excludes FERC account 874.

- The second difference relates to customer records and collections expenses (FERC account 903). In the abstract, customer records and billing costs are appropriate to include in a customer-specific cost calculation. However, in my review of the subaccounts that make up account 903, I found some subaccounts that were vague[41] and/or not customer-specific.[42] These questionable subaccounts are included in my maximum calculation and excluded from my minimum calculation.
- The final difference relates to the Company's cost of capital. The appropriate cost of capital is a contested issue in virtually every rate case, and I expect it to be contested in this case. However, the only cost of capital recommendation currently in the record is the Company's proposal. My maximum calculation uses the Company's proposed weighted cost of capital. Since there is currently no other proposal in the record, my minimum calculation uses the approved weighted cost of capital from CenterPoint's last rate case.

Q. What are the results of your customer-specific cost calculation?

A. My full customer-specific cost calculations are included as Schedule AT-D-3. A summary of the results, including a comparison of my calculations to the current basic charges and the Company's proposed basic charges, are included in Figure 4.

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[40] Specifically, the formula for account 874 is:

$$\text{Account } 874_{services} = \frac{\text{Account } 380_{Net\ Plant\ In\ Sservice}}{(\text{Account } 380_{Net\ Plant\ In\ Service} + \text{Account } 376_{Net\ Plant\ In\ Service})} x \text{ Account } 874_{total}$$

[41] E.g., 530999 (Materials & Supplies-Inventory Issue), 546010 (Other Services), 646620 (Service Company Non-Labor Other).

[42] E.g., 522062 (Entertainment), 562140 (Advertising-Gen), 562170 (Uniforms).

Figure 4, Customer-specific cost calculation results

	Current charge	CPE proposed	OAG customer-specific costs	
			Minimum	Maximum
Residential	$9.50	$11.00	$7.73	$8.57
Commercial A	$15.00	$17.50	$15.72	$17.29

As the table shows, even the current Residential basic charge amount exceeds the maximum customer-specific amount. With CenterPoint's proposed increase, the Residential basic charge would be 28 percent higher than the maximum customer-specific amount. Thus, CenterPoint's proposed increase is clearly inappropriate.

For Commercial A customers, the current basic charge amount is slightly below the minimum customer-specific amount, and so a small increase may be warranted. However, CenterPoint's proposed 17 percent increase is clearly too large, as it would set the basic charge above the maximum customer-specific cost.

Q. Should customer charge amounts be based solely on cost?

A. No. While the customer-specific cost calculation is an important factor, it is also necessary to consider state policy when determining the appropriate basic charge. I address these policy considerations in the following section.

C. Fixed Fee Policy Considerations

Q. Why is it important to consider policy in rate design?

A. As explained in Section III.A., when designing rates the Commission is exercising its legislative function, which requires "balancing both cost and non-cost factors and making choices among public policy alternatives" to determine the revenue apportionment and rate structure that are most consistent with the public interest.[43]

[43] *St. Paul Area Chamber of Commerce*, 251 N.W.2d at 358.

Q. Do Minnesota statutes require the Commission to set rates to encourage energy conservation and renewable energy use?

A. Yes. Minn. Stat. § 216B.03 (the "Reasonable Rate statute") states: **"**To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05." Notably, §§ 216B.241 and 216C.05 relate to energy conservation.

Q. Are there additional state statutes that emphasize the importance of energy conservation?

A. Yes. Minn. Stat. § 216C.05, subd. 1, states, "The legislature finds and declares that continued growth in demand for energy will cause severe social and economic dislocations, and that the state has a vital interest in providing for: increased efficiency in energy consumption . . . ." And Minn. Stat. § 216B.2401 states:

> The legislature finds that energy savings are an energy resource, and that cost-effective energy savings are preferred over all other energy resources. The legislature further finds that cost-effective energy savings should be procured systematically and aggressively in order to reduce utility costs for businesses and residents, improve the competitiveness and profitability of businesses, create more energy-related jobs, reduce the economic burden of fuel imports, and reduce pollution and emissions that cause climate change.

Q. How do CenterPoint's basic charges impact energy conservation?

A. Fixed fee amounts are applied *after* the revenue requirement and class revenue apportionment have been established. The revenue requirement and class revenue apportionment determine the total amount of revenue to be recovered from a given class, which is then divided between fixed fees and volumetric (per-therm) rates.[44] This means

[44] This is true for customers on a two-part rate, such as CenterPoint's Residential and Commercial A classes. For customers who also pay a demand charge—such as Large Firm customers—the class revenue apportionment must be divided between the customer charge, volumetric rates, and demand charges.

fixed fees and volumetric rates are a zero-sum game in the short run; increases to fixed fees must be offset with equivalent decreases to volumetric rates, and vice versa.

Thus, by definition, an increase to the basic charge will discourage conservation by lowering the value of each therm that is saved, which reduces the incentive to conserve energy. This also increases the payback period for investments in energy efficiency, such as building insulation or more efficient appliances. Similarly, a decrease to the basic charge amount will encourage conservation by increasing the value of each therm that is saved and by decreasing payback periods for investments in energy efficiency.

Q. How do Minnesota statutes' strong support for energy conservation impact your recommendation regarding CenterPoint's Residential and Commercial A basic charges?

A. The Minnesota Legislature has provided the Commission clear guidance on rate design: "To the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use."[45] To be consistent with this directive, basic charges should be set to the minimum reasonable amount.

Q. Are there other policy considerations that impact your recommendation regarding the appropriate basic charge amounts for Residential customers?

A. Yes, I also consider the impact of the Residential customer charge on low-income customers and people of color.[46]

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[45] Minn. Stat. § 216B.03.

[46] Throughout this testimony, a "person of color" is defined as any person who identifies as a race other than "white, non-Hispanic or Latino."

Q. Why is it important to consider impacts on low-income people and people of color when establishing utility rates?

A. Low-income people pay a disproportionate amount of their household income toward energy costs, a phenomenon referred to as "energy burden." In Minnesota, the average energy burden for all income levels was just 2 percent in 2018, but the energy burden for households at or below the federal poverty level was 16 percent, or eight times more than the statewide average.[47] Households earning between 101 and 150 percent of the federal poverty level faced average energy burdens of eight percent. This includes a significant number of Minnesotans: in 2018, 15 percent of Minnesota households had incomes at or below 150 percent of the federal poverty level ($37,650 for a family of four).[48] Because these households are paying a significantly higher proportion of their income toward energy costs—before factoring in the cost of housing, health care, and other essential needs—it is critical to assess the impacts of increased natural gas rates on this group of customers.

Further, Minnesotans who identify as people of color experience dramatically higher rates of poverty than those who identify as white. For example, Minnesotans who identify as American Indian/Indigenous or Black/African American face poverty rates of nearly thirty percent, compared to just seven percent for those who identify as white.[49] The Minnesota Pollution Control Agency has also found that people of color are also much more likely to reside in areas of environmental justice concern, meaning they tend to face greater exposure to the public health impacts of pollution.[50]

[47] U.S. Dep't of Energy, Low-Income Energy Affordability Data (LEAD) Tool (last visited Feb. 1, 2022).
[48] *Id.*
[49] Minn. Dep't of Health, People in Poverty in Minnesota (last visited Feb. 1, 2022).
[50] Minn. Pollution Control Agency, Understanding Environmental Justice in Minnesota (last visited Feb. 1, 2022).

Q. How will increasing Residential basic charges disproportionately harm low-income customers and people of color?

A. According to John Howat of the National Consumer Law Center, "The fixed charge increase penalty to low-volume consumers raises profound equity and social justice concerns."[51] Both across the country and in our region, low-income households tend to use less gas than higher-income households, and households headed by people of color use less gas on average that those headed by Caucasians. By definition, increased basic charges will increase bills for lower-use customers. Thus, the Company's proposal will disproportionately harm low-income households and people of color.

Q. How does average household gas usage vary by income in this region?

A. The U.S. Energy Information Administration's Residential Energy Consumption Survey[52] ("RECS") provides in-depth data on energy use in residential households. It does not provide enough granularity to estimate consumption patterns in the Company's specific service area, but it does provide data by region.

Figure 5 displays average annual Residential gas usage by household income for the West North Central Census Division[53] in the most recent RECS.[54] As the figure displays, low-income households tend to consume much less gas than high-income households: the average gas usage for customers with a household income of over

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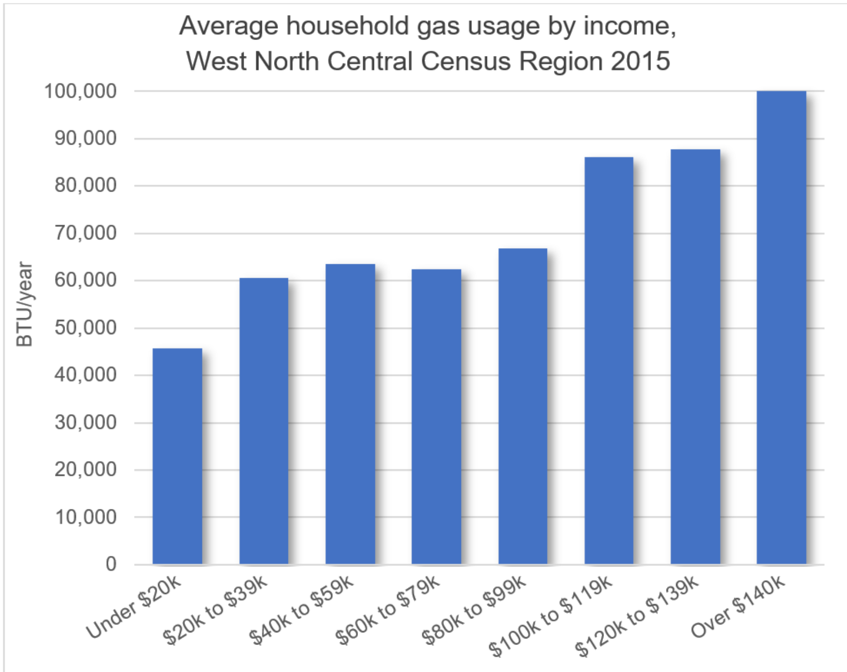
[51] JOHN HOWAT ET AL., U.S. DEP'T OF ENERGY, LAWRENCE BERKELEY NAT'L LAB., A CONSUMER ADVOCATE'S PERSPECTIVE ON ELECTRIC UTILITY RATE DESIGN OPTIONS FOR RECOVERING FIXED COSTS IN AN ENVIRONMENT OF FLAT OR DECLINING DEMAND 25 (June 2016).
[52] U.S. Energy Info. Admin., Residential Energy Consumption Survey (RECS) (last visited Feb. 1, 2022).
[53] The U.S. Census Bureau's "West North Central" Division comprises Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota.
[54] Compiled by the author using data from the U.S. Energy Information Administration. The analysis only includes households that use natural gas.

$140,000/year was more than double the average usage of households with an income of less than $20,000/year.

Figure 5, Average household gas usage by income in Minnesota's Census Division



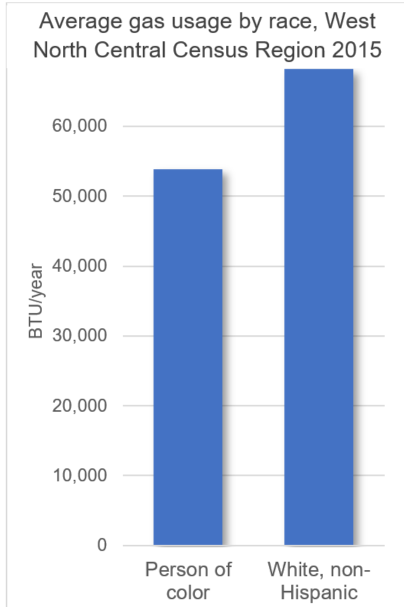
Q. Does the RECS also provide data on gas usage by race?

A. Yes. The RECS data include the respondent's racial identification for all observations.

Q. How does average gas use vary by racial identity in our region?

A. As shown in Figure 6, in the West North Central Census Division households for which the respondent identified as Caucasian used 27 percent more gas on average than households for which the respondent identified as a person of color.

Figure 6, Household gas usage by race in Minnesota's Census Division



Q. What do you conclude from Figures 5 and 6?

A. In our region, low-income households tend to use much less gas than high-income households, and households headed by people of color tend to use less gas than households headed by Caucasians. By definition, increasing fixed fees increases bills for low-use customers. Thus, the Company's proposed Residential basic charge increases will disproportionately harm low-income people and people of color.

Q. Are there additional benefits of lowering fixed fees for low-income customers and people of color?

A. Yes. As John Howat of the National Consumer Law Center has explained, "[o]n a very basic level, increased fixed charges diminish the ability of consumers to assert control over utility bills. For many of the reasons outlined here, the National Association of State Utility Consumer Advocates adopted a resolution unequivocally opposing increases in electric and natural gas utility fixed charges."[55] Conversely, decreasing fixed fees empowers customers by giving them more control over their energy bills. This benefit is available to all customers, but it is especially valuable to low-income customers who typically face much higher energy burdens than high- or mid-income customers.

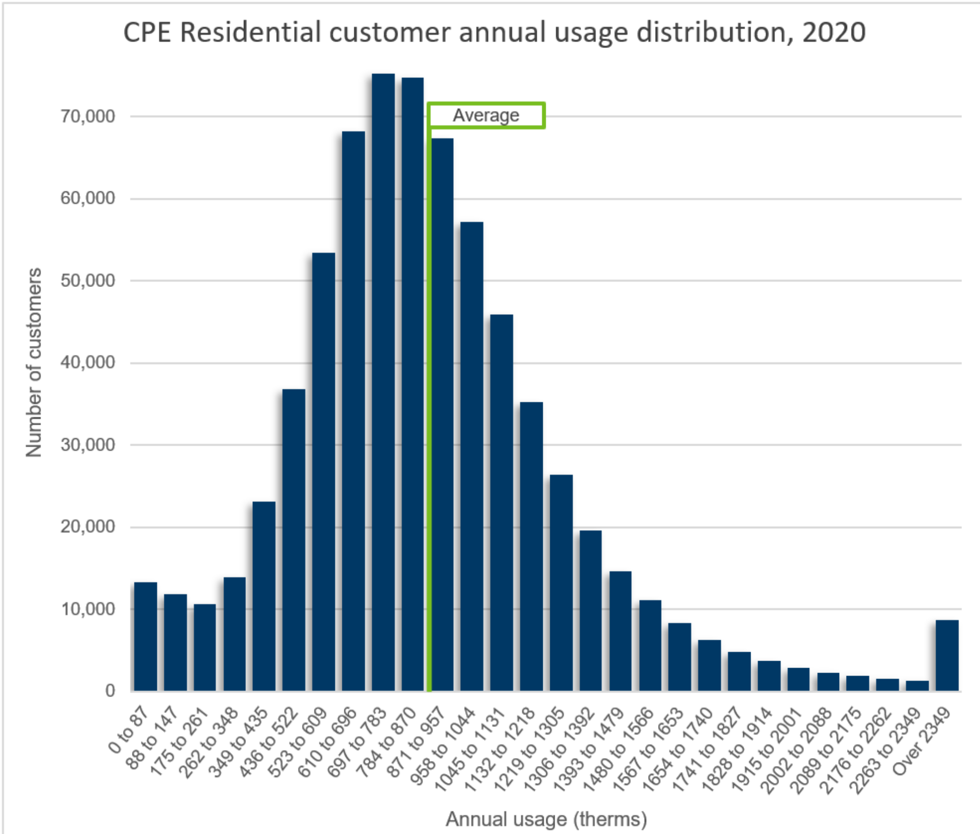
Q. How will the Company's proposed basic charge increases affect customer bills?

A. The Company's proposed basic charge increases will result in bill increases for most customers. This is because usage levels within customer classes are not distributed evenly. For example, within CenterPoint's Residential class, there are a relatively large number of customers with low usage, and a relatively small number of customers with very high usage. This is illustrated in Figure 7, below.[56] The small number of extremely high-usage customers significantly increase the class average usage. This means that most customer bills are lower than the overall class average, and, therefore, increasing basic charges will harm more customers than it will help.

[55] JOHN HOWAT ET AL., U.S. DEP'T OF ENERGY, LAWRENCE BERKELEY NAT'L LAB., A CONSUMER ADVOCATE'S PERSPECTIVE ON ELECTRIC UTILITY RATE DESIGN OPTIONS FOR RECOVERING FIXED COSTS IN AN ENVIRONMENT OF FLAT OR DECLINING DEMAND 25 (June 2016).

[56] Compiled by the author using data from CenterPoint's supplemental response to OAG IR 3003.

Figure 7, CenterPoint's Minnesota Residential customer usage distribution, 2020



Q. How do these policy considerations impact your basic charge recommendations?

A. Minnesota statutes require the Commission to set rates to encourage energy conservation to "the maximum reasonable extent."[57] Contrary to this directive, CenterPoint's proposed basic charge increases would discourage energy efficiency and conservation. Further, increasing customer charges would harm more customers than it would help, and it would disproportionately harm low-income customers and people of color. Conversely, decreasing customer charges would empower customers by giving them more control over their bills. All of these policy considerations weigh in favor of setting basic charges closer to the minimum values in my customer-specific cost calculations.

[57] Minn. Stat. § 216B.03.

D. CENTERPOINT'S SUPPORT FOR ITS PROPOSED BASIC CHARGE INCREASES

Q. What justifications does CenterPoint give for its proposed basic charge increases?

A. Mr. Zarumba gave four main arguments to support his proposed customer charge increases, which are listed below.

Q. Do you find Mr. Zarumba's arguments persuasive?

A. No. None of Mr. Zarumba's arguments are persuasive. I respond to each argument below.

Q. What was Mr. Zarumba's first justification for his proposed basic charge increases?

A. Mr. Zarumba argued the current basic charge amounts are lower than the customer-related costs calculated in his CCOSS.[58]

Q. Do you find this argument persuasive?

A. No. As detailed in subsection B, the relevant literature clearly states that fixed charges should only collect *customer-specific* costs, namely, the costs of service lines, metering, and billing. Mr. Zarumba's calculation of "customer-related" costs includes a vast number of additional costs, such as:

- A portion of the costs of the shared distribution system
- Miscellaneous intangible plant
- Office furniture and equipment
- Tool, shop, and garage equipment
- Laboratory equipment
- Water treatment
- Property insurance
- Administrative and general salaries
- Office supplies and expenses
- Regulatory commission expense, and
- Advertising expense.[59]

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[58] Zarumba Direct at 64 tbl.6.

[59] This list is far from exclusive. The full list of CenterPoint's customer-related costs by FERC account is included in the Company's response to OAG IR 7004.

Q. Why does Mr. Zarumba's list include costs that are clearly not customer-specific?

A. Many utility costs do not fit neatly into any of the cost classification buckets used in a CCOSS.[60] This includes many of the costs listed above. Utilities often allocate these costs using "internal" or "secondary" allocators, which are allocators that are derived from other calculations in the CCOSS. For example, CenterPoint allocates most all of its "General Plant" and "Intangible Plant" costs based on the weighted average of all other classified distribution plant accounts.[61] Mr. Zarumba's customer-related cost calculation includes a portion of these costs, even though they were not directly classified as customer-related in his CCOSS (for good reason). This approach is inappropriate. A fixed fee calculation should only include customer-specific costs.

Q. What was Mr. Zarumba's second justification for his proposed basic charge increases?

A. Mr. Zarumba argued that CenterPoint's residential and small business customer charges are lower than some other utilities in the region.[62]

Q. Do you find this argument persuasive?

A. No. It is inappropriate to compare a Minnesota utility's fixed charges with utilities in other states because those states do not have the same policy directives we do. Instead, it is more appropriate to compare CenterPoint's fixed fees to other Minnesota gas utilities. Mr. Zarumba's own analysis shows that CenterPoint's *current* basic charge is the highest residential gas monthly fixed charge in Minnesota.[63] Mr. Zarumba's proposed basic charge

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[60] Bonbright recognized this fact back in 1961, when he noted, "[Cost analysts are] the prisoner of [their] own assumption that 'the sum of the parts equals the whole."' [They are] therefore under impelling pressure to 'fudge' [their] cost apportionments by using the category of customers costs as a dumping ground for costs that [they] cannot plausibly impute to any of his other cost categories." BONBRIGHT, supra note 36, at 349.

[61] Zarumba Workpaper 2 at 1–2.

[62] Zarumba Direct at 65 and sched. 5.

[63] *Id.*, sched. 5 at 9.

would be 22 percent higher than the next highest gas fixed charge in Minnesota. Moreover, even if CenterPoint's fixed fees were lower than other Minnesota utilities, that alone would not justify its proposed basic charge increases. Each utility is unique, and fixed fee levels must be determined on a case-by-case basis.

Q. What was Mr. Zarumba's third justification for his proposed basic charge increases?

A. Mr. Zarumba argued that CenterPoint's Residential basic charge should be increased because it has not been increased since 2014.[64]

Q. Do you find this argument persuasive?

A. No. Fixed fee amounts should be set based on cost and policy considerations. If a fee was set too high or too low in a previous rate case, increasing it with inflation would not result in a fairer or more reasonable fee; it would simply carry the problem forward.

Moreover, it is important to consider *why* the Company's basic charge has not been increased since 2014. As Mr. Zarumba himself noted, in the Company's 2015 rate case the Commission expressly rejected CenterPoint's request to increase basic charges and in its 2017 and 2019 rate cases, all parties to the settlements agreed that the residential customer charge should not be increased.[65]

Thus, the Residential basic charge has remained steady not by accident or coincidence, but because of express agreements made by CenterPoint in 2017 and 2019 and the Commission's rejection of CenterPoint's requested increases in 2015.

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[64] Zarumba Direct at 66.
[65] *Id.*

Q. What was Mr. Zarumba's fourth justification for his proposed basic charge increases?

A. Mr. Zarumba argued his proposed basic charge increases would "act to stabilize non-gas revenues for the Company and costs for its customers."[66]

Q. Do you find this argument persuasive?

A. No, for two reasons. First, the increased basic charges do very little to stabilize customer bills. Gas usage tends to vary dramatically by season; even with the "stabilization" of increased basic charges, a residential customer who uses natural gas for heating would still see bills that are several times higher in January than in August.[67]

Second, for customers who would prefer more meaningful bill stabilization, CenterPoint offers a much more effective method: Average Monthly Billing. Customers who sign up for Average Monthly Billing—which is available to all firm customer classes—pay for their natural gas service in twelve approximately equal monthly payments throughout the year, subject to periodic reviews and true-ups.[68] This offers much greater bill stabilization than that of the Company's proposed basic charge increases. CenterPoint's average monthly billing program is also relatively popular: 23 percent of Residential customers used average monthly billing in 2020.[69]

[66] *Id.* at 67.
[67] See the bill comparisons in Zarumba Direct, sched. 6.
[68] For more details, see CenterPoint Energy Gas Rate Book at Section VI, Fourth Revised Pages 24–25 (June 1, 2021).
[69] CenterPoint's supplemental response to OAG IR 3001.

E. Basic Charge Conclusion

Q. What do you conclude regarding the Company's proposed basic charge increases for Residential and Commercial A customers?

A. CenterPoint's proposed basic charge increases for Residential and Commercial A customers should be rejected. The customer-specific cost calculations included in Schedule AT-D-3 provide a range of reasonable, cost-based basic charge amounts. However, while customer-specific costs are an important consideration, it is also necessary to consider state policy when determining the appropriate basic charge levels, such as:

- The Reasonable Rate Statute requires rates be set to encourage energy conservation to "the maximum reasonable extent"[70];
- Increasing basic charges would harm more customers than it would help, and it would disproportionately harm low-income customers and people of color; and
- Decreasing basic charges empowers customers by giving them more control over their bills, which is especially beneficial for low-income customers, who tend to have higher energy burdens.

Each of these considerations weighs in favor of setting basic charges closer to the minimum customer-specific calculation than the maximum.

At this time, I recommend the Residential basic charge be decreased to $8/month and the Commercial A basic charge be increased to $16/month. However, I acknowledge that issues raised in other parties' direct and rebuttal testimony may warrant an update to my calculations. Accordingly, I may update my calculations and recommendations in surrebuttal testimony.

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[70] Minn. Stat. § 216B.03.

V. HISTORICAL CONSTRUCTION COST TRENDS

Q. What is the purpose of this section of your testimony?

A. In this section, I discuss trends in the installed costs of CenterPoint's transmission pipelines, distribution mains, and service lines.

Q. How is this section of your testimony organized?

A. In subsection A, I detail CenterPoint's historical installation cost (per foot) for distribution mains, which has increased sharply over the past twelve years. I discus the implications of this trend in subsection B and provide recommendations in subsection C.

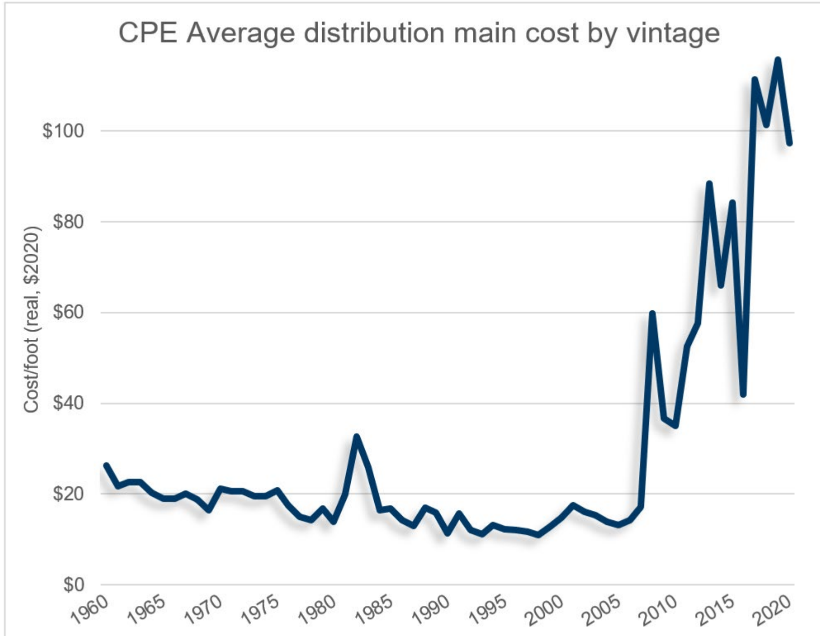
A. HISTORICAL DISTRIBUTION, TRANSMISSION, AND SERVICE LINE COSTS

Q. Have CenterPoint's per-foot construction costs for distribution mains increased in recent years?

A. Yes. While reviewing the Company's Minimum System study, I noticed an alarming trend: the average installation cost per foot has increased sharply over the past twelve years. This trend is displayed in Figure 8, below.[71] As the figure shows, the average (inflation-adjusted) installation cost declined steadily from 1960 through the middle 2000s, likely due to increased usage of plastic mains. However, beginning in 2008, costs increased sharply, and the average installed cost has continued to increase through 2020.

[71] Compiled by the author using data from CenterPoint's response to DOC IR 701, attachment 5.

Figure 8, CenterPoint distribution main installation cost, 1960–2020



Q. Have CenterPoint's per-foot construction costs for transmission pipelines increased in recent years?

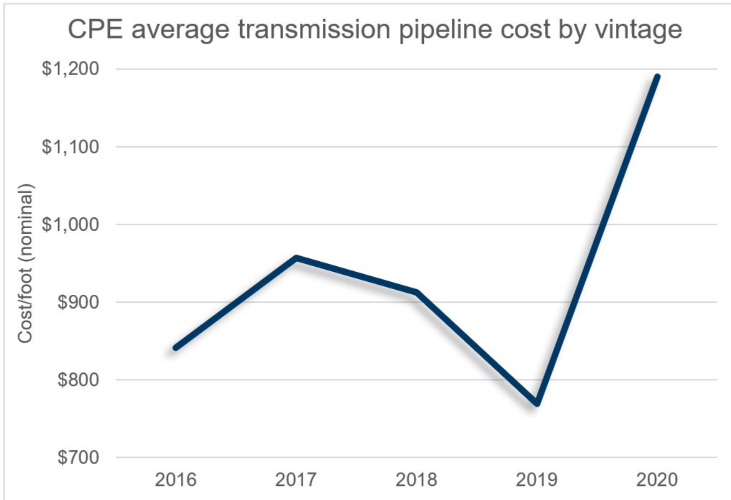
A. Yes. After noticing this trend for distribution mains, I asked the Company to provide historical construction cost data for transmission pipelines. Unfortunately, the Company's discovery response only provided data from 2017-2021, despite the fact that I requested annual data beginning in 1960.[72]

Since the Company refused to provide the data, I was not able to recreate the full historical trend for transmission pipeline construction costs. However, in an earlier discovery response the Company provided transmission pipeline construction cost data for projects completed from 2016 through 2020. Figure 9, below, summarizes these data.[73] As the figure shows, transmission pipeline installation costs have also increased

[72] CenterPoint's response to OAG IR 9022.
[73] Compiled by the author using data from CenterPoint's response to OAG IR 9002.

significantly in recent years. The average cost per foot in 2020 was 41 percent higher than 2016.

Figure 9, CenterPoint transmission pipeline installation cost, 2016–2020



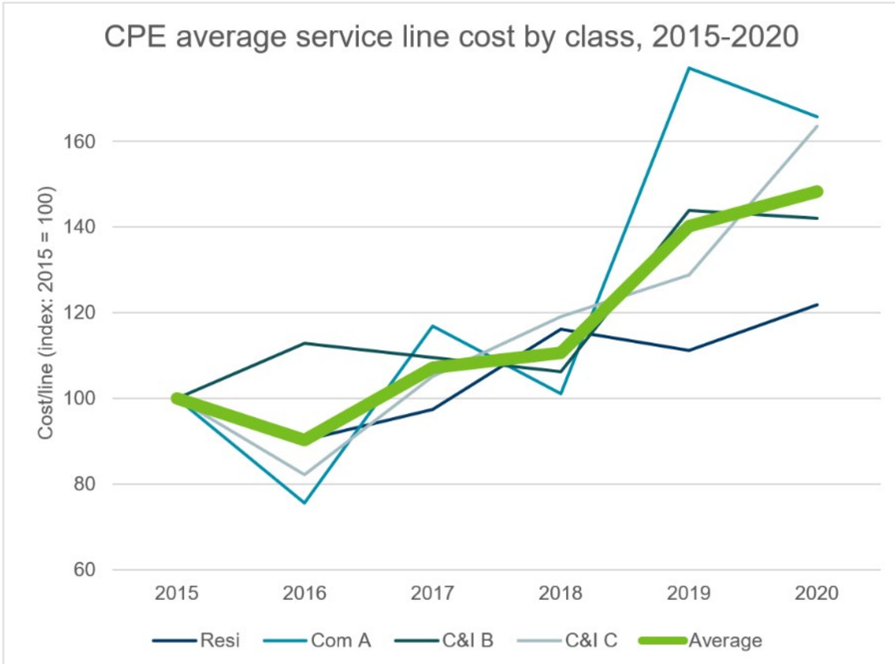
Q. Have CenterPoint's service line installation costs increased in recent years?

A. Yes. I also asked the Company to provide historical construction cost data for service line installations beginning in 1960. As for transmission pipelines, the Company's discovery response only provided data from 2017 to 2021.[74] Thus, I am unable to recreate the full historical trend for service line installation costs. However, the Company has provided service line installation cost data for projects completed between 2015 and 2020, which is summarized in Figure 10.[75] Because service line costs vary significantly between customer classes, Figure 10 shows both the cost increases for individual classes and the average of the class increases. The average installation cost increased for each customer class over this period, with an average of increase of 48 percent.

[74] CenterPoint's response to OAG IR 9022. Note that the Company's response to 9022 only provides cost data beginning in 2017, while the Company's response to OAG IR 9002 provided transmission pipeline cost data beginning in 2016.

[75] Compiled by the author using data from CenterPoint's response to DOC IR 707, attachment 1.

Figure 10, Change in service line installation cost, 2015–2020



B. IMPLICATIONS OF CONSTRUCTION COST INCREASES

Q. Does the Company acknowledge that its capital spending has increased significantly?

A. Yes. Ms. Singleton cited this trend in her Direct Testimony:

> [C]ompared to our prior history, our capital expenditures have increased significantly over the past several years. For example, for the ten years of 2002 through 2011, the Company's annual capital expenditures averaged $65 million in Minnesota. For the period 2012 through 2014, as the integrity management regulations took effect and the Company's TIMP and DIMP efforts kicked in, the Company's annual capital expenditures averaged $145 million. Since 2016, CenterPoint Energy Minnesota Gas' capital expenditures have averaged approximately $225 million annually and, based on the information currently available, are expected to be grow to at least $300 million annually for at least the next few years.[76]

[76] Singleton Direct at 22–23.

Q. Are the capital spending increases cited by Ms. Singleton the result of an increase in the length of pipe installed per year?

A. No, at least not for distribution mains. Ms. Singleton noted that average capital spending increased from $65 million/year in 2002–2011 to $225 million/year in 2016–2020. However, according to the distribution main installation data the Company has provided, these cost increases were not driven by an increase in the *amount* of pipe that was installed, but by a dramatic increase in per-foot installation costs.

Figure 11 illustrates this phenomenon.[77] This figure provides the average annual distribution main costs and length installed during the time periods highlighted by Ms. Singleton. The figure clearly corroborates the cost increases highlighted by Ms. Singleton, as the average annual costs increased dramatically over these periods.[78] However, the figure also illustrates that the cost increase is not due to the Company installing more pipe; in fact, the average length of mains installed per year was actually *lower* in 2016–2020 than it was in 2002–2011. Rather, the total spending increase appears to be the result of the dramatic increase in the cost per foot of line installed noted earlier.

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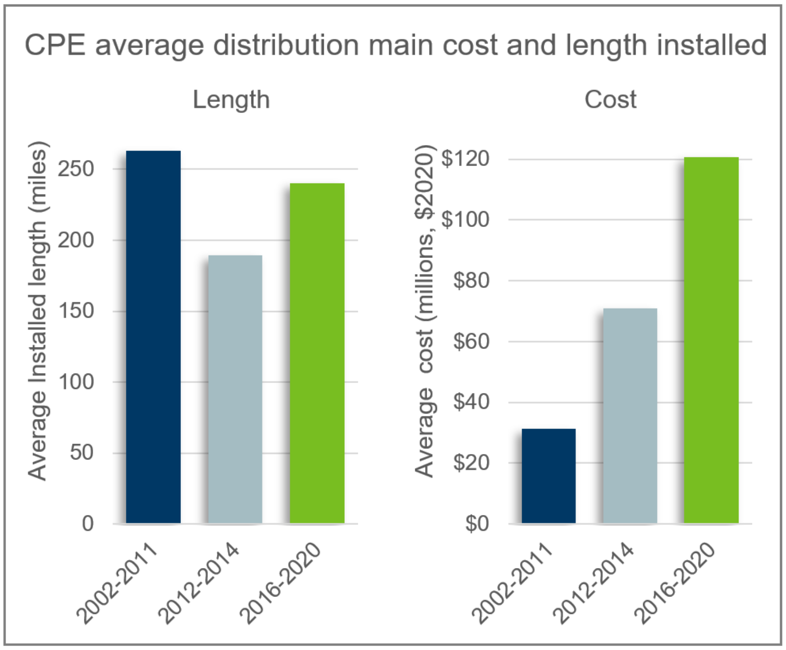
[77] Compiled by the author using data from CenterPoint's response to DOC IR 701, attachment 5.

[78] I note that the spending totals in Figure 11 are lower than those cited by Ms. Singleton because Figure 11 only includes distribution main costs. It was not possible to verify Ms. Singleton's figures because CenterPoint did not provide the data requested in OAG IRs 9022–24.

Figure 11, Annual average distribution main costs and installations



Q. Did the distribution main-installation cost spike coincide with the beginning of the Company's integrity management programs, as suggested by Ms. Singleton?

A. No. Ms. Singleton notes that the Company's Transmission and Distribution Integrity Management Programs took effect in 2012. However, as shown in Figure 8, above, the per-foot installation costs for distribution mains began its sharp increase in 2008, several years before the integrity management programs began.

Q. Has CenterPoint's increased capital spending had a significant impact on rates?

A. Yes, increased capital spending is the primary driver for this rate case, as it has been for CenterPoint's last three rate cases. According to Ms. Singleton, "By far the largest financial driver of this case is the continued capital investment since the Company's last rate case filed in 2019 and planned for 2022, principally involving our integrity management efforts."[79] CenterPoint has filed rate cases every other year since 2013, and

[79] Singleton Direct at 22.

Ms. Singleton indicated that the Company expects this trend to continue, largely due to the Company's planned pipe replacements.[80]

Q. Has CenterPoint finished replacing its most problematic pipes?

A. Yes. Ms. Singelton notes that the Company has "already replaced all known legacy cast iron" pipes on its system, as well as the majority of its bare steel pipes.[81] The cast iron pipe formerly on CenterPoint's distribution system was particularly vulnerable to failure and leakage.[82] Ms. Singleton notes that much of CenterPoint's methane emissions reductions in recent years "can be credited to the replacement of cast iron pipe across the Company's Minnesota system."[83]

Q. Has the Commission opened a docket to consider the future of natural gas?

Yes. In 2021, the Minnesota Legislature required the Commission to "initiate a proceeding to evaluate changes to natural gas utility regulatory and policy structures needed to meet or exceed Minnesota's greenhouse gas emissions reductions goals."[84] Though the Commission has not yet established the scope of this new docket, it will likely include consideration of technologies that could replace natural gas, such as air-source heat pumps, ground-sourced district energy, or hydrogen produced using carbon-free electricity.

These technological advances create significant stranded-asset risk. For example, if the new pipe CenterPoint is installing is not capable of transporting hydrogen, and the Commission determines that a transition to hydrogen is the most cost-effective means of meeting Minnesota's greenhouse-gas-reduction goals, then CenterPoint's new pipe may

[80] *Id.* at 24.
[81] *Id.* at 4.
[82] *See, e.g.*, Docket No. G-008/GR-13-316, Direct Testimony of Talmadge R. Centers at 32 (Aug. 2, 2013).
[83] Singleton Direct at 13.
[84] *See* 2021 Minn. Laws, ch. 4, art. 8, § 27; *In the Matter of a Commission Evaluation of Changes to Natural Gas Utility Regulatory and Policy Structures to Meet State Greenhouse Gas Reduction Goals*, Docket No. G-999/CI-21-565.

become stranded before the end of its useful life. Ms. Singleton notes that the new pipeline replacements can accommodate a minimal amount of hydrogen blending, but if the Company "looks to increase the level of hydrogen infused into the distribution system, additional levels of pipeline replacement to accommodate higher levels of hydrogen could be needed."[85]

C. CONSTRUCTION COST RECOMMENDATIONS

Q. What do you conclude regarding CenterPoint's construction cost trends?

A. This appears to be an inopportune time for the Company to make discretionary pipe replacements. After decades of relative stability, the cost per foot of distribution main installations has skyrocketed since 2008. The Company is installing roughly the same length of distribution mains per year as in the 2000s, but total costs to customers are several times higher. Due to these high costs, CenterPoint has filed five rate cases in the past nine years, and the Company plans to continue filing biennial rate cases going forward. Moreover, CenterPoint has already removed its most problematic distribution mains, having eradicated its cast iron mains and replaced the majority of its bare steel mains. Finally, there is uncertainty regarding the future of the gas industry, which creates significant stranded asset risk.

At this time, it appears to be in customers' interest to slow the pace of transmission pipeline and distribution main replacements. If the Company disagrees with this conclusion, I request it provide the following in its rebuttal testimony:

- Historical per-foot installation cost data for transmission pipelines;
- A list of what it believes to be the main causes of the per-foot cost increases;

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[85] Singleton Direct at 4–5.

- An explanation of why the cost increases began several years before the integrity management programs;
- A projection of future per-foot installation costs for transmission pipelines and distribution mains; and
- A discussion of the feasibility of extending the replacement timeline for integrity management projects by five years, including any risks to this approach (quantified where possible).

VI. DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM

Q. What is the purpose of this section of your testimony?

A. In this section, I discuss portions of the Company's Distribution Integrity Management Program.

Q. How is this section of your testimony organized?

A. The Company's Bare Steel and Legacy Steel Main Replacement Projects are discussed in subsections A and B, respectively, and the Company's Legacy Plastic Main Replacement Project is addressed in subsection C.

A. BARE STEEL MAIN REPLACEMENT PROJECT

Q. What is the Company's Bare Steel Main Replacement Project?

A. As explained on pages 35–39 of Mr. Wiinamaki's direct testimony, some of the distribution mains on the Company's system are made of uncoated steel—or "bare steel"—pipes. These pipes are vulnerable to corrosion, which can lead to gas leaks.[86] The Company began systematically replacing these pipes in 2012, and the Company has since replaced

[86] Wiinamaki Direct at 37.

71 percent of its bare steel mains.[87] The Company plans to replace the remainder of its bare steel mains by the end of 2026.

Q. How much does the Company propose to spend on the Bare Steel Main Replacement Project in the test year?

A. The Company plans to replace 22.7 miles of bare steel mains, for a total test year capital cost of $27.5 million.[88]

Q. How did the Company develop its test year capital cost projection?

A. Unlike the Company's other category of integrity replacements—the Transmission Main Replacement Project—the proposed test year costs for the Bare Steel Main Replacement Project are not based on work orders for specific projects.[89] Rather, the proposed test year cost was developed by multiplying the proposed length of bare steel mains to be replaced by the Company's estimated costs per mile for 2021 Bare Steel Main Replacement projects, as detailed in Mr. Wiinamaki's Workpaper 5.

Q. Have you identified any issues with the test year cost estimates for the Bare Steel Mains Replacement Project?

A. Yes. The test year cost estimates are not based on *actual* project costs from 2021, but rather from *estimated* costs per foot for 2021 projects. Estimating this year's costs using estimated costs from last year risks creating a feedback loop: if costs were overestimated in the prior year, that overestimate will be carried forward to the current year.

[87] *Id.* at 35–36.
[88] *Id.* at 37 tbl.7.
[89] In fact, as of January 19, 2022, the Company had only finalized the design of 20 percent of the total proposed test year Project replacement length (CenterPoint's response to OAG IR 9013). See also the discussion of the main replacement design process included in CenterPoint's response to OAG IR 9015.

Q. Did the Company overestimate the costs of Bare Steel Main Replacement Projects in 2021?

A. It appears so. In its response to OAG IR 9012, the Company provided forecast and actual costs for 2021 Bare Steel Main Replacement Projects. Based on this response, the Company overestimated the cost of the main replacements by eleven percent and the cost of service line replacements by twenty percent.[90]

Q. Did you recalculate Mr. Wiinamaki's Bare Steel Main Replacement Project test year cost estimate using actual historical costs?

A. Yes. The Company provided actual 2021 costs for its Bare Steel and Legacy Steel Replacement Projects.[91] I replicated Mr. Wiinamaki's calculation of test year program costs using the average actual 2021 costs for large (≥10") and small (≤8") mains. The results are summarized in Figure 12. As the figure shows, test year costs would be roughly $11 million lower if calculated using actual 2021 costs rather than projections.

Figure 12, Bare Steel Main Replacement Project test year costs

Bare Steel Main Replacement Project	**CPE request**	**2021 actuals**	**Timeline extension**
Miles replaceed	22.7	22.7	7.1
Capital cost	$27,455,130	$16,414,687	$5,111,630

I also calculated the test year costs for the Bare Steel Main Replacement Project if the timeline were extended by five years, meaning the remaining bare steel mains would

[90] CenterPoint's response to OAG IR 9012, attach. 1. I note that the Company's January 19, 2022 response stated that "costs are still being received on many work orders." Thus, the actual costs may increase if additional costs are received. Since I have not received an update to this response, however, my analysis uses the cost data as provided in OAG IR 9012.

[91] CenterPoint's responses to OAG IRs 9012 and 9014. This practice is consistent with Mr. Wiinamaki's workpapers, which use the same cost per mile for Bare Steel and Legacy Steel replacement projects. *See* Wiinamaki Workpaper 6 at 1 ("2022 costs are on a per-mile basis, with the average cost per mile taken from the Bare Steel Main Replacement project (Workpaper 5), since the work of these two projects is expected to be similar.")

be replaced over the next ten years rather than the next five as proposed by CenterPoint. Extending the Project timeline would further reduce test year costs, to $5.1 million.

Q. What is your recommendation regarding test year Bare Steel Main Replacement Project costs?

A. It appears that test year Bare Steel Main Replacement Project costs should be reduced to $16.4 million if the Company is permitted to replace 22.7 miles of mains, as requested.[92] Moreover, as explained in Section V, it also appears reasonable to slow the pace of main replacements; extending the timeline for the Project by five years would reduce test year costs to $5.1 million.

At this time, I recommend reducing test year Project costs to $5.1 million. However, in Section V I requested CenterPoint provide additional information in rebuttal testimony regarding its construction cost trends and the potential impacts of extending main replacement project timelines. Thus, I will reserve my final recommendation for surrebuttal testimony, to allow consideration of the Company's rebuttal testimony.

B. LEGACY STEEL MAIN REPLACEMENT PROJECT

Q. What is the Company's Legacy Steel Main Replacement Project?

A. As explained on pages 39–41 of Mr. Wiinamaki's direct testimony, "legacy" steel mains are those that have coatings—i.e., they're not bare—but were installed before 1950. Mr. Wiinamaki states that these mains were "manufactured, constructed and/or operated using legacy practices that are no longer considered sufficient for effective risk management" and that they "present an elevated risk of equipment failure and corrosion failure."[93] As of

[92] As noted above, CenterPoint's January 19, 2022 response to OAG IR 9012 stated that "costs are still being received on many work orders." Thus, my calculations may need to be adjusted if the Company supplements its IR response.
[93] Wiinamaki Direct at 40.

2020, the Company had 39.3 miles of legacy steel mains remaining on its distribution system. The Company plans to replace the remainder of its legacy steel mains by the end of 2028.[94]

Q. How much does the Company propose to spend on the Legacy Steel Main Replacement Project in the test year?

A. The Company plans to replace 2.15 miles of legacy steel mains, for a total test year capital cost of $4.09 million.[95]

Q. How did the Company develop its test year capital cost projection?

A. Like the Bare Steel Main Replacement Project, proposed test year costs were not based on work orders for specific projects, but rather were estimated using estimated installation costs from 2021 projects.[96] This raises the same concern highlighted in subsection A: if costs were overestimated in the prior year, that overestimate will be carried forward to the current year.

Q. Did the Company overestimate the costs of Legacy Steel Main Replacement Projects in 2021?

A. Yes, though by a smaller amount than for the Bare Steel Main Replacement Project. According to CenterPoint's response to OAG IR 9014, the Company overestimated 2021 Legacy Steel Main Replacement Project costs by 4.5 percent.[97]

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[94] *Id.* at 39.
[95] *Id.* at 39 tbl.8.
[96] This calculation is included in Mr. Wiinamaki's Workpaper 6.
[97] CenterPoint's response to OAG IR 9014, attach. 1. I note that the Company's January 19, 2022 response stated that "costs are still being received on many 2021 work orders." Thus, the actual costs may increase if additional costs are received. Since I have not received an update to this response, however, my analysis uses the cost data as provided in the response to OAG IR 9014.

Q. Did you recalculate Mr. Wiinamaki's Legacy Steel Main Replacement Project test year cost estimate using actual historical costs?

A. Yes. I replicated Mr. Wiinamaki's calculation of test year program costs using the average actual 2021 costs for Bare Steel and Legacy Steel Replacement Projects. The results are summarized in Figure 13. As the figure shows, using actual 2021 costs would reduce test year costs by roughly two million dollars.

Figure 13, Legacy Steel Main Replacement Project test year costs

Legacy Steel Main Replacement Project			
	CPE request	**2021 actuals**	**Timeline extension**
Miles replaceed	2.2	2.2	1.8
Capital cost	$4,090,000	$2,075,182	$1,765,245

I also calculated the test year costs for the Legacy Steel Main Replacement Project if the timeline were extended by five years, meaning the remaining legacy steel mains would be replaced over the next twelve years rather than the next seven as proposed by CenterPoint. Extending the timeline would further reduce test year costs, to $1.8 million.

Q. What is your recommendation regarding test year Legacy Steel Main Replacement Project costs?

A. It appears that test year Legacy Steel Main Replacement Project costs should be reduced to $2.07 million if the Company is permitted to replace 2.2 miles of mains, as requested, or to $1.73 million if the replacement timeline is extended.[98]

At this time, I recommend reducing test year Project costs to $1.73 million. However, in Section V, I requested that CenterPoint provide additional information in rebuttal testimony regarding its construction cost trends and the potential impacts of

[98] As noted above, CenterPoint's January 19, 2022 response to OAG IR 9014 stated that "costs are still being received on many 2021 work orders." Thus, my calculations may need to be adjusted if the Company supplements its IR response.

extending main replacement project timelines. Thus, I will reserve my final recommendation for surrebuttal testimony, to allow consideration of the Company's rebuttal testimony.

C. LEGACY PLASTIC MAIN REPLACEMENT PROJECT

Q. What is the Company's Legacy Plastic Main Replacement Project?

A. As explained on pages 41–44 of Mr. Wiinamaki's direct testimony, "legacy" plastic mains are those that were installed before the mid-1980s. Mr. Wiinamaki states that these mains are "made of resins that are susceptible to slow crack growth failure when subjected to stresses such as frost heaving, subsidence, excavation, rock impingement, and settlement."[99] At the end of 2020, the Company had 1,441 miles of legacy plastic mains remaining on its distribution system. The Company plans to continue replacing the remainder of its legacy plastic mains through 2036.[100]

Q. How much does the Company propose to spend on the Legacy Plastic Main Replacement Project in the test year?

A. The Company plans to replace 26.52 miles of legacy plastic mains, for a total test year capital cost of $11.2 million.[101]

Q. How did the Company develop its test year capital cost projection?

A. The Company's Legacy Plastic Mains Replacement Project cost calculation was more complex than the calculation for bare and legacy steel projects, using a cost multiplier for work located in Minneapolis that was based on data that was not included in Mr. Wiinamaki's workpapers.[102]

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[99] Wiinamaki Direct at 42.
[100] Wiinamaki Workpaper 7 at 3.
[101] Wiinamaki Direct at 42 tbl.9.
[102] Wiinamaki Workpaper 7 at 2 nn.4–5.

In order to verify the Company's proposed test year cost, I replicated Mr. Wiinamaki's calculation using average historical plastic main replacement costs from 2015 to 2020.[103] The results are summarized in Figure 14, below. As the figure shows, using historical actual costs would reduce test year costs by roughly $800,000.

Figure 14, Legacy Plastic Main Replacement Project test year costs

Legacy Plastic Main Replacement Project		
	CPE request	**2015-2020 actuals**
Miles replaceed	26.5	26.5
Capital cost	$11,202,115	$10,417,725

I did not calculate the impact of a timeline extension on Legacy Plastic Main Replacement Project costs, since CenterPoint's current proposed replacement timeline extends through 2036. However, I note that CenterPoint's proposed timeline includes a significant increase in the amount of pipe replaced per year over the next four years.[104] Given these facts, the appropriate timeline for the Legacy Plastic Main Replacement Project may merit Commission consideration.

Q. What is your recommendation regarding test year Legacy Plastic Main Replacement Project costs?

A. I recommend reducing test year Legacy Plastic Main Replacement Project costs to $10.4 million.

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[103] CenterPoint's response to OAG IR 9018, attach. 1. None of the 2021 Legacy Plastic replacement projects were located in Minneapolis (*See* Wiinamaki Workpaper 7 at 2 n.3). Accordingly, my calculation used actual costs for small diameter (≤8") plastic mains installed in the Bare Steel Main Replacement project from 2015-2020.

[104] Wiinamaki Workpaper 7 at 3. Under CenterPoint's proposal, the miles replaced per year increases from 26.52 in the test year to 53.03 in 2023, 75.05 in 2024, and 99.91 in 2025 and beyond.

VII. MARKETING PROGRAMS

Q. What is the purpose of this section of your testimony?

A. In this section, I discuss CenterPoint's proposed Marketing Programs. As detailed on pages 9–14 of Todd Berreman's direct testimony, CenterPoint is proposing three Marketing Programs: Residential Water Heater, Foodservice, and Commercial & Industrial Market Rebate. The total test year cost for these programs is $308,866, with the lion's share devoted to the Residential Water Heater Program.

Q. How is this section of your testimony organized?

A. I give an overview of the Company's proposed Residential Water Heater Program and its claimed benefits in subsection A. In subsection B, I provide an economic analysis of the Water Heater Program, which refutes the purported benefits of the program. I discuss the Foodservice and Commercial & Industrial Market Rebate programs in subsection C. In subsection D, I explain why I recommend all three Marketing Programs be rejected.

A. RESIDENTIAL WATER HEATER PROGRAM

Q. Please summarize The Company's proposed Residential Water Heater Program.

A. CenterPoint proposes to provide a financial incentive to homebuilders to install natural gas water heaters in new residential homes. Mr. Berreman does not state the amount of the incentive, but dividing the Company's proposed program cost ($239,958) by the projected number of new water heaters (4,225) yields an average per-water-heater incentive of roughly $57.[105] Mr. Berreman also projects O&M costs of $39,884, for a full program cost of $279,842. CenterPoint requests permission to recover the program's costs in rates.

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[105] Berreman Direct, sched. 2 at 2.

Q. What justifications does CenterPoint provide for this program?

A. CenterPoint provides two main justifications for the program. First, the Company claims natural gas water heaters have "much lower operating costs and higher energy efficiency" than electric water heaters.[106] Second, the Company claims the additional consumption from gas water heaters would benefit all customers by spreading the Company's costs over a larger amount of sales and thus "reduce the overall costs of service for all customers."[107]

Q. Is CenterPoint's claim that natural gas water heaters have lower operating costs and higher energy efficiency than electric water heaters accurate?

A. No. Residential water heaters come in a variety of configurations. While it may be true that some natural gas water heaters have lower operating costs than some electric water heaters, it is not categorically true that natural gas water heaters have lower operating costs and higher energy efficiency than electric water heaters. In fact, the lowest-cost and highest-efficiency water heaters available today are electric heat pump water heaters.[108]

Q. Does CenterPoint's second claimed benefit justify its Residential Water Heater Program?

A. No. CenterPoint claims that additional natural gas usage from water heating will benefit all customers by spreading the Company's "fixed" costs over a larger amount of volumetric sales. However, this is not necessarily a net benefit for consumers. CenterPoint's argument ignores the fact that its residential natural gas customers are also customers of an electric

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[106] Berreman Direct at 13.

[107] *Id.* at 11.

[108] *See* U.S. ENVTL. PROTECTION AGENCY AND U.S. DEP'T OF ENERGY, ENERGY STAR® RESIDENTIAL WATER HEATERS: FINAL CRITERIA ANALYSIS (Apr. 1, 2008). Moreover, electric heat pump water heater technology has become even more efficient since this report was published: electric heat pump water heaters on the market today have energy factors of up to 3.75. U.S. Envtl. Protection Agency and U.S. Dep't of Energy, ENERGY STAR Certified Water Heaters, https://www.energystar.gov/productfinder/product/certified-water-heaters/ (last visited Feb. 1, 2022).

utility. If a new home installs an electric water heater rather than gas, that additional electricity consumption would put downward pressure on consumers' electric rates.

In the next subsection, I provide a detailed comparison of the utility rate reduction impacts of different types of electric and natural gas water heaters.

B. Residential Water Heater Utility Bill Mitigation Comparison

Q. What is the purpose of your water heater utility bill mitigation comparison?

A. As mentioned above, the purported benefit of the Residential Water Heater Program for non-participating customers is that the additional natural gas usage from water heating will spread the Company's fixed costs over a larger amount of volumetric sales, thus putting downward pressure on rates.

However, this is not necessarily a net benefit for consumers. CenterPoint's argument ignores the fact that virtually all of its residential natural gas customers are also customers of an electric utility. If a new home installs an electric water heater instead of a gas water heater, that additional electricity consumption would exert downward pressure on the consumer's electric rates.

Thus, while CenterPoint's Residential Water Heater Program undoubtedly benefits CenterPoint by increasing its sales, whether the program provides a net benefit to consumers depends on which technology type exerts more downward pressure on utility rates.

To answer this question, I prepared a residential water heater utility bill mitigation comparison, included as Schedule AT-D-5, below.

Q. How does your analysis calculate the utility bill mitigation benefits of natural gas water heaters?

A. I used the amount calculated by Mr. Berreman in Schedule 2 of his Direct Testimony, which he derived by multiplying expected gas usage from the new water heaters (in therms) by the per-therm Residential Distribution Charge—i.e., the variable rate excluding the cost of gas.

Q. How does your analysis calculate the utility bill mitigation benefits of electric water heaters?

A. To estimate the utility bill mitigation benefits of electric water heaters, I applied Mr. Berreman's methodology to electric rates. Mr. Berreman's calculation multiplies the expected water heater gas usage by the Residential Distribution Charge—i.e. the variable rate excluding the cost of gas. For electric water heaters, I multiplied the expected water heater electricity consumption by the state average residential electricity rate minus the fuel cost of electricity generation.[109]

Q. What are the results of your utility bill mitigation comparison?

A. The results of my analysis are summarized in Figure 15, below. Mr. Berreman's analysis found that the Company's proposed Water Heater Program would produce roughly $200,000 in bill mitigation benefits per year. Using the same methodology, I estimate that the bill mitigation benefits of high-efficiency electric water heaters would be over $800,000 per year, or four times larger than natural gas water heaters.

[109] To my knowledge, the average cost of fuel is not publicly available for all of Minnesota's electric utilities. However, Minnesota is a member of the Midcontinent Independent System Operator (MISO), an organized electricity market that coordinates electricity generation across 15 U.S. states and the Canadian province of Manitoba. MISO publishes "Locational Marginal Prices" for each hour of the year. These Locational Marginal Prices are roughly equivalent to the cost of gas, because they include the electricity generators' cost of fuel and variable O&M. Accordingly, I used the 2020 average Locational Marginal Price for the Minnesota Hub as the fuel price of electricity.

Figure 15, Water Heater Bill Mitigation By Type

	Annual Bill Mitigation	
	Per-Water Heater	**Program Total**
Natural gas	$44	$186,462
Electric Heat Pump	$190	$803,402
Electric Resistance	$398	$1,680,413

I also calculated the utility rate reduction benefits of lower efficiency—i.e., electric resistance—water heaters. These models have lower up-front costs but higher operational costs, which typically make them more expensive on a total cost basis. For these low-efficiency electric water heaters, the utility bill mitigation benefits would be roughly nine times larger than natural gas water heaters.

Q. Can electric water heaters provide additional benefits that are not included in your calculation?

A. Yes. There is a considerable amount of flexibility in *when* electric tanked water heaters consume electricity. This means utilities can control electric water heaters to reduce peak demand or direct them to charge more when there is excess renewable energy generation. Utilities across the country are already taking advantage of this flexibility, including Minnesota's own Great River Energy, which states that a utility-controlled electric water heater could save a customer up to $200 a year.[110]

Q. What do you conclude based on your utility bill mitigation comparison?

A. For both low- and high-efficiency models, the utility bill mitigation impacts of electric water heaters are significantly larger than their natural gas counterparts. This means CenterPoint's proposed Residential Water Heater Program would provide a smaller net

[110] Great River Energy, Community storage, https://greatriverenergy.com/smart-energy-use/beneficial-electrification/community-storage/ (last visited Feb. 1, 2022).

benefit to consumers than if new houses were equipped with electric water heaters, even without considering the actual costs of the Program. Because CenterPoint's proposed Residential Water Heater Program would be a net detriment to consumers, it is not in the public interest and should be rejected.

C. FOODSERVICE AND COMMERCIAL & INDUSTRIAL MARKET REBATE PROGRAMS

Q. Did CenterPoint propose additional marketing programs?

A. Yes. In addition to the water heater program, CenterPoint also proposed a Foodservice Program and Commercial & Industrial Market Rebate Program. These programs are considerably smaller than the water heater program, with total costs of $40,531 and $34,421, respectively.[111] The projected net benefits of these programs are also much smaller, at $39,059 and $28,122, respectively.[112]

Q. Did you perform a bill impact mitigation analysis for the proposed Foodservice Program?

A. No. Mr. Berreman's cost–benefit analysis for the Residential Water Heater Program contained detailed information on the number of rebates issued and the expected amount of usage per water heater, with clear, publicly available supporting evidence.[113] The Foodservice Program, on the other hand, had much less supporting evidence. The expected usage was "based on the BTU/hr input size and operating hours of qualifying customers in previous years," and Mr. Berreman stated that the usage of this equipment "varies significantly based on the size of facility and its operating hours."[114] This is not enough information to complete an analysis of alternative technologies.

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[111] Berreman Direct, sched. 3 at 2 and sched. 4 at 2.
[112] *Id.* Totals are in Net Present Value.
[113] CenterPoint's response to OAG IR 6001.
[114] CenterPoint's response to OAG IR 6002.

Q. Would you expect a bill mitigation analysis for the Foodservice Program to come to a different conclusion than the Residential Water Heater Program?

A. No. The underlying premise for the two programs is the same, namely that increased gas usage would put downward pressure on rates. If these restaurants (etc.) instead used electric appliances, the increased electricity usage would put downward pressure on their electric rates. Further, the alleged net benefits of this program are much smaller than that of the water heater program. Thus, I suspect that if there were enough information to complete a full bill mitigation comparison, the results would be comparable to the water heater program.

Q. Did you perform a bill impact mitigation analysis for the proposed C&I Market Rebate Program?

A. No. Similar to the Foodservice Program, the Company provided very little information to support the assumptions underlying its analysis.[115] Further, based on Mr. Berreman's testimony, this program appears better suited to CenterPoint's Conservation Improvement Program ("CIP") than to a marketing program. Mr. Berreman claims the program will provide equipment rebates "to invest in new, more efficient technologies which, in turn, reduce their energy usage."[116] The whole premise of the proposed Marketing Programs is that they will *increase* gas usage, and thus put downward pressure on rates. If the purpose of the C&I Market Rebate is to encourage customers to invest in more energy-efficient appliances, it appears to be better suited as a CIP offering.

[115] CenterPoint's response to OAG IR 6003.
[116] Berreman Direct at 14.

Q. What is your recommendation regarding the Foodservice and C&I Market Rebate Programs?

A. I recommend that the programs be rejected.

D. MARKETING PROGRAM RECOMMENDATIONS

Q. What is your recommendation with respect to CenterPoint's proposed Marketing Programs?

A. CenterPoint's proposed Marketing Programs would benefit the Company by increasing its sales, but they would not benefit consumers. The Company's proposals rest on the faulty premise that increased natural gas usage will benefit non-participating customers by putting downward pressure on rates. This argument ignores the fact that CenterPoint's customers also use electricity, and so electric appliances would put downward pressure on their electric rates. My analysis of the Residential Water Heater Program demonstrates that electric water heaters provide far greater bill mitigation than gas water heaters. The same is likely true for the Foodservice and C&I Market Rebate Programs.

For these reasons, I recommend that the Company's proposed Marketing Programs be rejected and their costs be disallowed.

VIII. RECOMMENDATIONS AND CONCLUSION

Q. Will you please restate the recommendations made in this testimony?

A. Yes. Regarding the embedded class cost of service study, I recommend that the Commission:

- Require CenterPoint to file Peak & Average and Basic Customer CCOSSes in the initial filing of its next rate case.

Regarding class revenue apportionment:

- I recommend the following class rate increases:
  - Residential: 4.1%
  - C&I A: 5.7%
  - C&I B: 6.5%
  - C&I C – Sales: 8.1%
  - C&I C – Transport: 13.3%
  - Small DF - A – Sales: 11.3%
  - Small DF - A – Transport: 9.7%
  - Small DF- B – Sales: 11.7%
  - Small DF - B – Transport: 9.9%
  - Large Firm – Sales: 15.7%
  - Large Firm – Transport: 24.9%
  - Large DF Sales: 19.9%
  - Large DF Transport: 21.5%
- If the final approved revenue requirement is lower than the amount requested by CenterPoint, I recommend that the final class increases be determined by multiplying the PUC's approved Total Company revenue increase by the ratio of the OAG's recommended class increase to CPE's proposed Total Company increase.

Regarding basic charges:

- At this time, I recommend the Residential basic charge be decreased to $8/month and the Commercial A basic charge be increased to $16/month.

Regarding CenterPoint's historical construction cost trends:

- At this time, it appears to be in customers' interest to slow the pace of transmission pipeline and distribution main replacements.
- If the Company disagrees with this conclusion, I request that it provide the following in its rebuttal testimony:
  - Historical per-foot installation cost data for transmission pipelines;
  - A list of what it believes to be the main causes of the per-foot cost increases;
  - An explanation of why the cost increases began several years before the integrity management programs;
  - A projection of future per-foot installation costs for transmission pipelines and distribution mains; and
  - A discussion of the feasibility of extending the replacement timeline for integrity management projects by five years, including any risks to this approach (quantified where possible).

Regarding CenterPoint's Distribution Integrity Management Program:

- At this time, I recommend that test year Bare Steel Main Replacement Project costs be reduced from $27.5 million to $5.1 million;
- At this time, I recommend that test year Legacy Steel Main Replacement Project costs be reduced from $4.1 million to $1.8 million; and
- At this time, I recommend that test year Legacy Plastic Main Replacement Project costs be reduced from $11.2 million to $10.4 million.

Regarding the Company's proposed Marketing Programs:

- I recommend that the Company's proposed Marketing Programs be rejected and their proposed $308,866 cost be removed from the test year.

Q. Does this conclude your Direct Testimony?

A. Yes.

Twite Curriculum Vitae

Professional Experience

Rates Analyst, Office of the Minnesota Attorney General, November 2020 to present

Selected docket work:

Docket	**Utility**	**Topic**
20-719	Otter Tail Power	CCOSS, rate design (rate case)
20-850	Minnesota Power	Residential rate design

Senior Policy Associate, Fresh Energy, October 2016 to November 2020

Selected docket work:

Docket	**Utility**	**Subject**
07-1199	All electric utilities	Carbon dioxide regulatory cost values
12-233	Minnesota Power	Residential rate design
17-775	Xcel Energy	Residential rate design pilot
19-337	Minnesota Power	Commercial electric vehicle charging rates
19-442	Minnesota Power	Rate design (rate case)
19-524	CenterPoint Energy	Rate design (rate case)
20-86	Xcel Energy	Large C&I rate design
20-331	Otter Tail Power	Residential rate design pilot

Rates Analyst, Minnesota Public Utilities Commission, January 2014 to October 2016

Selected docket work:

Docket	**Utility**	**Subject**
08-948	All electric utilities	Smart grid investments
13-868	Xcel Energy	Rate design (rate case)
15-424	CenterPoint Energy	Rate design (rate case)
15-556	All electric utilities	Grid modernization
15-662	Xcel Energy	Residential rate design
15-826	Xcel Energy	Rate design (rate case)
15-879	Great Plains Natural Gas	Rate design (rate case)

Education

M.P.P. Master of Public Policy, Advanced Policy Analysis Methods, May 2013
University of Minnesota, Minneapolis, MN

B.A. Bachelor of Arts in Political Science *summa cum laude*, May 2009
University of Minnesota, Minneapolis, MN

State	Utility	Docket No.	Utility mains classification/allocation	Commission staff position
Illinois				
	Ameren Illinois	20-308	Capacity and Energy (Peak & Average)	Supported use of P&A
	Nicor Gas	18-1775	Capacity, Customer, and Energy (min sys)	Did not oppose Company blended approach
	North Shore Gas	20-810	Capacity and Energy (Average & Peak)	Accepted Company's CCOSS
	People's Gas	14-225	Capacity and Energy (Average & Peak)	Accepted Company's CCOSS
Iowa				
	Black Hills Energy	RPU-2021-002	Capacity and Energy (Average & Excess)	Did not oppose use of A&E
	Interstate Power and Light	RPU-2019-002	Capacity and Energy (Average & Excess)	Did not oppose use of A&E
Michigan				
	Consumers Energy	U-21148	Capacity and Energy (Average & Peak)	Pending
	DTE Gas	U-20940	Capacity and Energy (Average & Peak)	Supported use of A&P
	SEMCO Energy	U-20479	Capacity and Energy (Average & Peak)	Did not oppose use of A&P
North Dakota				
	Montana-Dakota Utilities	PU-15-95	Capacity, Customer, and Energy (min sys)	Opposed min sys, recommend 100% Capacity
	Montana-Dakota Utilities	PU-17-295	Capacity, Customer, and Energy (min sys)	Opposed min sys, recommend 100% Capacity
	Montana-Dakota Utilities	PU-20-379	Capacity and Customer (min size and zero int)	Opposed zero int, recommend Cap, Cust & Energy
	Xcel Energy	PU-21-381	Capacity, Customer, and Energy (min sys)	Pending
South Dakota				
	Mid-American	NG14-005	Capacity and Energy (Peak & Average)	Did not oppose use of P&A
	Montana-Dakota Utilities	NG15-005	Capacity (75%) and Customer (25%)	Opposed use of minimum system study
	NorthWestern Energy	NG11-003	Capacity (95%) and Energy (5%)	Supported Company's CCOSS
Wisconsin				
	Madison Gas & Electric	3270-UR-124	CCOSS A: Capacity, Customer, and Energy CCOSS B: Capacity and Energy (A&E)	Staff considered both COSSs
	Wisconsin Power & Light	6680-UR-123	CCOSS A: Capacity, Customer, and Energy CCOSS B: Capacity and Energy (A&E)	Staff considered both COSSs
	Xcel Energy	4220-UR-125	CCOSS A: Capacity, Customer, and Energy CCOSS B: Capacity and Energy (A&E)	Staff considered both COSSs

Customer-specific cost calculations

Residential customer class				
FERC account	**Description**	**Minimum**	**Maximum**	**Calculation**
Net plant in service				
380	Service lines	$241,079,543	$241,079,543	a
381	Meters	$38,064,178	$38,064,178	b
382/383	Meter installations & house regulators	$54,900,145	$54,900,145	c
	Total net plant	$334,043,866	$334,043,866	sum(a:c)=d
	Pre-tax return	8.73%	9.16%	e
Total rate base and taxes		**$29,153,732**	**$30,586,169**	d*e=f
Depreciation expenses				
380	Service lines	$21,106,264	$21,106,264	g
381	Meters	$1,861,198	$1,861,198	h
382	Meter installations	$2,931,924	$2,931,924	i
Other expenses				
874	Service lines	$0	$2,214,085	j
878	Meter & house regulator	$4,091,317	$4,091,317	k
879	Customer installations	$3,539,671	$3,539,671	l
892	Maintenance of services	$3,709,647	$3,709,647	m
893	Maintenance of meters & house reg.	$1,355,324	$1,355,324	n
902	Meter reading	$1,358,391	$1,358,391	o
903	Customer records and collection	$8,214,079	$13,017,863	p
Total expenses		**$48,167,815**	**$55,185,684**	sum(g:p)=q
Total customer-specific revenue requirement		**$77,321,547**	**$85,771,852**	f+q=r
Annual customer bills		10,005,871	10,005,871	s
Customer charge ($/month)		**$7.73**	**$8.57**	r/s=t

Commercial A customer class

FERC account	Description	Minimum	Maximum	Calculation
Net plant in service				
380	Service lines	$19,270,916	$19,270,916	a
381	Meters	$2,143,696	$2,143,696	b
382/383	Meter installations & house regulators	$3,091,863	$3,091,863	c
	Total net plant	$24,506,475	$24,506,475	sum(a:c)=d
	Pre-tax return	8.73%	9.16%	e
Total rate base and taxes		$2,138,807	$2,243,894	d*e=f
Depreciation expenses				
380	Service lines	$1,687,149	$1,687,149	g
381	Meters	$104,819	$104,819	h
382	Meter installations	$165,120	$165,120	i
Other expenses				
874	Service lines	$0	$176,985	j
878	Meter & house regulator	$230,414	$230,414	k
879	Customer installations	$188,014	$188,014	l
892	Maintenance of services	$296,534	$296,534	m
893	Maintenance of meters & house reg.	$76,329	$76,329	n
902	Meter reading	$46,389	$46,389	o
903	Customer records and collection	$436,302	$691,461	p
Total expenses		$3,231,070	$3,663,214	sum(g:p)=q
Total customer-specific revenue requirement		$5,369,876	$5,907,108	f+q=r
Annual customer bills		341,699	341,699	s
Customer charge ($/month)		$15.72	$17.29	r/s=t

Distribution Integrity Management Program test year cost calculations

Bare Steel Main Replacement Project (Wiinamaki WP 5)				
Line	**Description**	**CPE proposed**	**Calculated with 2021 actual costs**	**2021 Actuals & timeline extension**
1	**Cost of main replacements**			
2	Miles to be replaced	22.68	22.68	7.06
3	Small-diameter (=< 8") main:			
4	Miles to be replaced	20.04	20.04	6.24
5	x Average cost per mile	$360,000	$380,255	$380,255
6	Estimated cost	$7,214,400	$7,620,303	$2,373,007
7	Large-diameter (>= 10") main:			
8	Miles to be replaced	2.64	2.64	0.82
9	x Average cost per mile	$5,400,000	$2,112,168	$2,112,168
10	Estimated cost	$14,256,000	$5,576,123	$1,736,437
11				
12	**Cost of main replacements**	**$21,470,400**	**$13,196,426**	**$4,109,445**
13				
14	**Cost of service line replacements:**			
15	Miles to be replaced	22.68	22.68	7.06
16	x Average cost per mile	$263,877	$141,899	$141,899
17	**Cost of service line replacements**	**$5,984,730**	**$3,218,262**	**$1,002,186**
18				
19	**Total cost**	**$27,455,130**	**$16,414,687**	**$5,111,630**
20				
21	**Cost in millions, rounded**	**$27.5**	**$16.4**	**$5.1**

Legacy Steel Main Replacement Project (Wiinamaki WP 6)				
Line	**Description**	**CPE proposed**	**Calculated with 2021 actual costs**	**2021 Actuals & timeline extension**
1	**Cost of main replacements**			
2	Miles to be replaced	2.15	2.15	1.83
3	Small-diameter (=< 8") main:			
4	Miles to be replaced	1.60	1.60	1.33
5	x Average cost per mile	$360,000	$380,255	$380,255
6	Estimated cost	$577,037	$608,407	$505,777
7	Large-diameter (>= 10") main:			
8	Miles to be replaced	0.55	0.55	0.46
9	x Average cost per mile	$5,400,000	$2,112,168	$2,112,168
10	Estimated cost	$2,946,039	$1,161,692	$965,730
11				
12	**Cost of main replacements**	$3,523,076	$1,770,100	$1,471,507
13				
14	**Cost of service line replacements:**			
15	Miles to be replaced	2.15	2.15	1.83
16	x Average cost per mile	$263,877	$141,899	$141,899
17	**Cost of service line replacements**	$566,924	$305,082	$259,517
18				
19	**Total cost**	$4,090,000	$2,075,182	$1,731,024
20				
21	**Cost in millions, rounded**	$4.09	$2.08	$1.73

Legacy Plastic Main Replacement Project (Wiinamaki WP 7)			
Line	**Description**	**CPE proposed**	**Calculated with 2015-2020 actual costs**
1	**Miles of mains abandoned**	26.52	26.52
2	Minneapolis	2.25	2.25
3	Non-Minneapolis	24.27	24.27
4			
5	**Average cost per mile**		
6	Minneapolis	$903,666	$931,272
7	Non-Minneapolis	$377,695	$342,806
8			
9	**Project cost**		
10	Minneapolis	$2,037,044	$2,099,273
11	Non-Minneapolis	$9,165,071	$8,318,452
12			
13	**Total cost**	**$11,202,115**	**$10,417,725**
14			
15	**Cost in millions, rounded**	**$11.2**	**$10.4**

	Water Heater Energy (BTU)	Water Heater Fuel (Dth, kWh)	Utility Rate (excluding fuel)	Annual Bill Mitigation	
				Per-WH	Program Total
Natural gas	11,049,575	17.6	$2.5043	$44	$186,462
Electric Heat Pump	11,049,575	1,665	$0.1142	$190	$803,402
Electric Resistance	11,049,575	3,482	$0.1142	$398	$1,680,413

State of Minnesota
Minnesota Department of Commerce

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case Date of Request: 12/8/2021
Requested From: CenterPoint Energy Minnesota Gas Response Due: 12/20/2021

Analyst Requesting Information: Michael Zajicek

Type of Inquiry: Cost of Service

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
DOC 701	Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy. Topic: Cost studies Please provide all CCOSS spreadsheets as Excel files including any supporting spreadsheets, with all links and formulas intact. **Response:** CCOSS spreadsheets are provided as Excel files as follows:

Designation	Description	File name	Comment
Schedule 2	CenterPoint Energy's Class Cost of Service Study Using the Minimum System Method	DOC 701_CPE Exhibit RZ - D Schedule 2,3,4_ CARD Model.xlsx	Attachment 1
Schedule 3	Non-Gas Revenue Surplus/Deficiency and Proposed Changes in Class Revenues	DOC 701_CPE Exhibit RZ - D Schedule 2,3,4_ CARD Model.xlsx	Attachment 1
Schedule 4	Summary of Present and Proposed Class Revenues	DOC 701_CPE Exhibit RZ - D Schedule 2,3,4_ CARD Model.xlsx	Attachment 1
Schedule 5	American Gas Association – Natural Gas Utility Rate Structure: The Customer Charge Component – 2015 Update	DOC 701_CPE Exhibit RZ-D Schedule 5.xlsx	Attachment 2

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

Schedule 6	Bill Comparison of Present and Proposed Rates	DOC 701_CPE Exhibit RZ-D Schedule 6.xlsx	Attachment 3
Schedule 7	Proposed Tariff – Income Tax Rider (Section V, Page 31)	PDF provided	NA
Workpaper 1	Cost Allocation & Rate Design (CARD) Model – Class Cost of Service Study Using the Minimum System Method	DOC 701_CPE Exhibit RZ - D Schedule 2,3,4_ CARD Model.xlsx	Attachment 1
Workpaper 2	Detailed Explanation of the Cost Classification and Allocation Methods Used in the Class Cost of Service Study Using the Minimum System Method	DOC 701_CPE Exhibit RZ-WP Workpaper 2.xlsx	Attachment 4
Workpaper 3	Minimum System Method – Distribution Mains	DOC 701_CPE Exhibit RZ_WP Workpaper 3.xlsx	Attachment 5
Workpaper 4	Derivation of the Capacity Carrying Capability of the Minimum Size Distribution Main	DOC 701_CPE Exhibit RZ_WP Workpaper 4.xlsx	Attachment 6
Workpaper 5	Derivation of the Relative Demand Assessment Allocation Factor	DOC 701_CPE Exhibit RZ - D Schedule 2,3,4_ CARD Model.xlsx	Attachment 1
Workpaper 6	Billing Determinants	DOC 701_CPE Exhibit RZ_WP Workpaper 6.xlsx	Attachment 7 ---Supporting documentation from witness Fitzpatrick and witness Dean
Workpaper 7	Dual Fuel Market Rate Customers Incremental Cost	DOC 701_CPE Exhibit RZ-WP Workpaper 7.xlsx	Attachment 8

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

For comparison of unit costs by vintage - not used in analysis of min system

Vintage	Length	$	2,021	Unit $ 2021
1908	6	2	219	36.58
1909	728	225	27,229	37.40
1910	599	410	49,749	83.05
1911	201	162	19,630	97.66
1912	104	57	6,853	65.89
1913	-	-	-	
1914	-	-	-	
1915	77	43	5,160	67.02
1916	-	-	-	
1917	-	-	-	
1918	13	12	791	60.84
1919	-	-	-	
1920	-	-	-	
1921	-	-	-	
1922	-	-	-	
1923	106	92	5,598	52.81
1924	60	60	3,666	61.10
1925	28	67	4,040	144.29
1926	-	-	-	
1927	2,483	7,670	437,645	176.26
1928	474	571	32,588	68.75
1929	183	97	5,534	30.24
1930	301	224	12,770	42.42
1931	997	839	47,897	48.04
1932	1,084	7,141	432,923	399.38
1933	13	102	6,588	506.74
1934	1,368	932	60,242	44.04
1935	29,329	295,141	19,085,772	650.75
1936	441	200	12,128	27.50
1937	3,117	10,189	581,354	186.51
1938	17,051	50,907	2,743,335	160.89
1939	149,282	219,153	11,809,891	79.11
1940	28,459	101,290	5,458,397	191.80
1941	54,418	440,243	23,724,184	435.96
1942	17,392	57,142	2,917,273	167.74
1943	2,080	71,269	3,638,467	1,749.26
1944	3,199	5,243	267,656	83.67
1945	3,453	18,389	891,884	258.29
1946	72,837	473,476	20,875,976	286.61
1947	49,377	494,706	18,456,350	373.78
1948	72,740	733,886	24,547,223	337.47
1949	61,772	473,807	14,825,579	240.00
1950	81,190	603,752	18,301,224	225.41
1951	113,813	543,530	15,063,543	132.35
1952	97,957	1,074,050	28,157,531	287.45
1953	343,208	1,399,820	33,945,631	98.91
1954	394,158	2,036,115	47,024,553	119.30
1955	269,041	1,366,871	30,834,057	114.61
1956	152,063	838,748	17,686,633	116.31
1957	219,617	1,207,354	23,900,681	108.83
1958	282,620	1,633,617	31,070,752	109.94
1959	776,185	3,178,879	58,179,489	74.96
1960	1,089,120	3,269,871	57,668,629	52.95
1961	942,640	2,366,096	40,265,140	42.72

1962	1,108,475	2,937,696	49,130,440	44.32
1963	666,620	1,786,330	28,878,964	43.32
1964	1,011,403	2,457,972	38,453,159	38.02
1965	711,527	1,641,075	24,871,607	34.96
1966	970,208	2,309,688	34,453,358	35.51
1967	933,987	2,410,856	33,251,729	35.60
1968	1,461,403	3,698,989	47,735,752	32.66
1969	990,016	2,305,923	25,377,428	25.63
1970	1,013,352	3,209,304	33,174,796	32.74
1971	594,133	1,913,692	17,533,757	29.51
1972	867,907	2,879,499	25,002,426	28.81
1973	921,114	3,084,503	25,498,357	27.68
1974	874,525	3,246,754	23,529,981	26.91
1975	546,967	2,357,343	13,850,145	25.32
1976	675,977	2,607,968	13,687,573	20.25
1977	746,239	2,618,477	12,532,947	16.79
1978	952,808	3,441,023	14,611,113	15.33
1979	849,802	3,995,845	17,243,120	20.29
1980	1,081,082	4,777,869	17,326,154	16.03
1981	638,420	4,451,786	15,754,819	24.68
1982	489,814	5,953,288	21,956,670	44.83
1983	640,061	6,361,252	21,414,092	33.46
1984	949,917	6,242,235	19,061,967	20.07
1985	919,460	6,389,780	20,146,059	21.91
1986	1,017,969	6,123,215	18,098,495	17.78
1987	1,348,162	7,670,702	22,878,410	16.97
1988	1,656,841	12,872,162	38,252,813	23.09
1989	1,456,001	11,014,509	30,594,743	21.01
1990	1,767,297	10,076,884	24,813,820	14.04
1991	1,302,920	10,722,338	26,703,002	20.49
1992	1,407,442	9,237,419	22,603,953	16.06
1993	1,667,850	10,361,751	23,824,784	14.28
1994	2,406,341	18,177,069	42,585,418	17.70
1995	1,946,195	13,974,378	29,592,153	15.21
1996	1,379,623	10,032,318	20,903,595	15.15
1997	1,698,033	12,295,623	27,099,286	15.96
1998	1,774,264	12,311,884	24,209,478	13.64
1999	1,665,028	13,664,679	27,029,582	16.23
2000	1,674,319	16,446,048	32,038,791	19.14
2001	1,620,785	19,406,431	39,342,937	24.27
2002	1,963,205	22,014,822	43,016,309	21.91
2003	2,120,052	23,188,438	43,146,378	20.35
2004	1,792,644	18,203,697	30,870,052	17.22
2005	1,703,536	16,808,897	25,518,596	14.98
2006	1,894,449	21,138,542	30,343,239	16.02
2007	1,248,483	17,221,861	23,946,873	19.18
2008	1,080,851	53,763,945	80,327,869	74.32
2009	658,029	20,025,059	25,394,164	38.59
2010	588,575	17,351,682	22,314,739	37.91
2011	848,291	38,701,823	48,364,364	57.01
2012	738,727	37,766,435	43,571,269	58.98
2013	958,804	76,282,359	88,518,590	92.32
2014	1,298,967	78,290,128	91,197,872	70.21
2015	1,324,168	102,101,023	118,739,560	89.67
2016	1,143,460	44,367,369	50,764,347	44.40
2017	1,310,893	138,287,183	161,173,423	122.95
2018	1,132,063	111,172,994	126,515,055	111.76
2019	1,481,868	169,215,940	178,168,055	120.23
2020	1,269,484	123,578,390	122,967,288	96.86
2021	5	1,825	1,825	364.91
	76,296,225	1,429,931,421	2,952,999,992	11,201
check	*76,296,225*	*1,429,931,421*	*2,952,999,992*	

State of Minnesota
Minnesota Department of Commerce

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case Date of Request: 12/8/2021
Requested From: CenterPoint Energy Minnesota Gas Response Due: 12/20/2021

Analyst Requesting Information: Michael Zajicek

Type of Inquiry: Cost of Service

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
DOC 706	Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy. Topic: Cost studies Did the Company perform a Zero intercept study while preparing its CCOSS? Please provide a discussion of why the Company choose not to include a zero intercept study in this filing. **Response:** Yes, a Zero intercept study was prepared as part of the CCOSS. The filing did not present the Zero intercept study because, similar to the previous CCOSS study completed in 2019, the results were anomalous when compared to the Minimum System Approach. The Zero intercept study performed by the Company is attached hereto as Attachment 1.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.891543189
R Square	0.794849258
Adjusted R Square	0.794035168
Standard Error	18.97043289
Observations	254

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	351371.6392	351371.6392	976.3650437	1.17879E-88
Residual	252	90689.08565	359.877324		
Total	253	442060.7248			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2.4257814	1.437778742	1.687172948	0.092807466	-0.405812212	5.257375011	-0.405812212	5.257375011
X Variable 1	2.256829648	0.072225851	31.24684054	1.17879E-88	2.114586441	2.399072854	2.114586441	2.399072854

PLANT	MATL	SIZE	SIZE^2	DESCRIPTION	VINTAGE	LENGTH	AMOUNT	HWIndex	AMOUNT2021	UNITCOST2021
3763	PL	0.5	0.25	PIPE, PLASTIC,	1990	5249	4923.81	0.482935154	10195.59244	1.942387586
3763	PL	0.5	0.25	PIPE, PLASTIC,	2020	11125	546679.22	0.993174061	550436.4655	49.4774351
3763	PL	0.625	0.390625	PIPE, PLASTIC,	1976	9095	7944.27	0.230375427	34484.01644	3.791535618
3763	PL	0.625	0.390625	PIPE, PLASTIC,	1977	1820	3779.98	0.245733788	15382.41861	8.451878358
3763	PL	0.625	0.390625	PIPE, PLASTIC,	1978	4213	6699.18	0.264505119	25327.22245	6.011683468
3763	PL	0.625	0.390625	PIPE, PLASTIC,	1979	5670	15531.7	0.288395904	53855.48047	9.498321071
3763	PL	0.625	0.390625	PIPE, PLASTIC,	1980	6349	20296.27	0.319112628	63602.21508	10.01767445
3763	PL	0.625	0.390625	PIPE, PLASTIC,	1981	2727	12276.15	0.348122867	35263.84265	12.93136877
3763	PL	0.625	0.390625	PIPE, PLASTIC,	1982	1814	5501.17	0.375426621	14653.11645	8.077792974
3763	PL	0.625	0.390625	PIPE, PLASTIC,	1983	1614	4501.7	0.389078498	11570.15877	7.168623774
3763	PL	0.625	0.390625	PIPE, PLASTIC,	1984	1095	2946.05	0.397610922	7409.37897	6.766556137
3763	PL	1	1	PIPE, PLASTIC,	1966	3068	1762.65	0.124573379	14149.49178	4.611959511
3763	PL	1	1	PIPE, PLASTIC,	1976	3843	11981.02	0.230375427	52006.50163	13.53278731
3763	PL	1	1	PIPE, PLASTIC,	1978	8170	4473.52	0.264505119	16912.79174	2.070109148
3763	PL	1	1	PIPE, PLASTIC,	1979	1766	1720.06	0.288395904	5964.231716	3.377254652
3763	PL	1	1	PIPE, PLASTIC,	1980	2340	5475.6	0.319112628	17158.83209	7.332834225
3763	PL	1	1	PIPE, PLASTIC,	1981	8697	16102.45	0.348122867	46255.07696	5.318509482
3763	PL	1	1	PIPE, PLASTIC,	1982	1082	4802.92	0.375426621	12793.23236	11.8236898
3763	PL	1	1	PIPE, PLASTIC,	1985	1148	2185.86	0.401023891	5450.697702	4.747994514
3763	PL	1	1	PIPE, PLASTIC,	1994	4832	6637.59	0.523890785	12669.7972	2.622060679

3763	PL	1	1	PIPE, PLASTIC,	2008	2253	18696.46	0.791808874	23612.33957	10.48039928
3763	PL	1.125	1.265625	PIPE, PLASTIC,	1993	1040	6341.49	0.511945392	12387.0438	11.91061904
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1968	68406	69160.18	0.133105802	519588.019	7.595649782
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1969	164063	222225.19	0.139931741	1588097.09	9.679800379
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1970	87719	146397.95	0.146757679	997548.8221	11.37209524
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1971	99298	181198	0.156996587	1154152.478	11.62311908
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1972	166261	268114.54	0.163822526	1636615.838	9.843654483
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1973	185955	400305.07	0.170648464	2345787.71	12.61481385
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1974	114724	242110.67	0.19112628	1266757.613	11.04178387
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1975	128118	293726.83	0.216723549	1355306.475	10.57857971
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1976	248383	580522.7	0.230375427	2519898.535	10.14521338
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1977	322881	762096.64	0.245733788	3101309.938	9.605117482
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1978	362807	894926.33	0.264505119	3383398.899	9.325616372
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1979	296524	773801.55	0.288395904	2683122.534	9.048584716
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1980	318848	946198.72	0.319112628	2965093.315	9.29939443
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1981	121783	578313.74	0.348122867	1661234.567	13.64093976
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1982	87007	384027.26	0.375426621	1022908.974	11.75662848
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1983	145670	626081.79	0.389078498	1609140.039	11.04647518
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1984	204651	705550.42	0.397610922	1774474.447	8.670734308
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1985	200381	700164.99	0.401023891	1745943.337	8.713118194
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1986	247009	833297.12	0.407849829	2043146.913	8.27154846
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1987	236568	685414.32	0.419795222	1632734.925	6.901757317
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1988	285621	925244.35	0.441979522	2093409.997	7.329328013
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1989	81632	232344.76	0.469283276	495105.5613	6.065091647
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1990	35585	156892.64	0.482935154	324873.0991	9.129495548
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1991	17453	128552.76	0.493174061	260664.0739	14.93520162
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1992	29840	168075.7	0.5	336151.4	11.26512735
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1993	30365	133072.3	0.511945392	259934.5593	8.560334574
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1994	23513	89901.34	0.523890785	171603.2093	7.298226906
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1996	2140	16040.9	0.54778157	29283.38754	13.68382595
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1997	2358	8595.3	0.558020478	15403.19817	6.532314743
3763	PL	1.25	1.5625	PIPE, PLASTIC,	1999	4285	30681.67	0.581911263	52725.6851	12.30471064
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2000	2872	32993.48	0.593856655	55557.98644	19.3447028
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2002	1188	26271.28	0.610921502	43002.70972	36.1975671
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2004	5868	63486.14	0.645051195	98420.31228	16.77237769
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2005	15041	128730.24	0.682593857	188589.8016	12.53838186
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2006	1184	17474.81	0.721843003	24208.60203	20.44645442
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2007	1522	26283.13	0.766211604	34302.70419	22.53791339
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2008	1554	66362.13	0.791808874	83810.79349	53.93229954
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2009	1097	48709.16	0.841296928	57897.70337	52.77821638

3763	PL	1.25	1.5625	PIPE, PLASTIC,	2010	1336	70077.01	0.822525597	85197.36071	63.77047957
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2012	2696	93561.82	0.875426621	106875.6852	39.64231648
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2013	2816	37917.21	0.889078498	42647.76403	15.14480257
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2015	2195	21059.67	0.90443686	23284.84268	10.60812878
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2016	1585	48348.95	0.912969283	52957.91533	33.41193396
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2018	1467	71613.24	0.938566553	76300.65207	52.01135111
3763	PL	1.25	1.5625	PIPE, PLASTIC,	2019	1152	69370.86	0.964163823	71949.24595	62.45594266
3763	PL	1.5	2.25	PIPE, PLASTIC,	1970	97616	153738.33	0.146757679	1047565.83	10.73149719
3763	PL	1.5	2.25	PIPE, PLASTIC,	1972	3682	11330.59	0.163822526	69163.80979	18.78430467
3763	PL	1.5	2.25	PIPE, PLASTIC,	1973	3397	6727.55	0.170648464	39423.443	11.60537033
3763	PL	1.5	2.25	PIPE, PLASTIC,	1974	14811	26467.86	0.19112628	138483.6246	9.350052302
3763	PL	1.5	2.25	PIPE, PLASTIC,	1977	1549	3533.58	0.245733788	14379.7075	9.283219819
3763	PL	1.5	2.25	PIPE, PLASTIC,	1994	1725	2369.58	0.523890785	4523.041954	2.622053307
3763	PL	2	4	PIPE, PLASTIC,	1967	57778	100753.55	0.129692833	776862.8987	13.4456523
3763	PL	2	4	PIPE, PLASTIC,	1968	130508	216470.81	0.133105802	1626306.342	12.46135365
3763	PL	2	4	PIPE, PLASTIC,	1969	121477	247320.6	0.139931741	1767437.459	14.5495646
3763	PL	2	4	PIPE, PLASTIC,	1970	171262	408168.27	0.146757679	2781239.607	16.23967726
3763	PL	2	4	PIPE, PLASTIC,	1971	101904	303647.32	0.156996587	1934101.408	18.9796417
3763	PL	2	4	PIPE, PLASTIC,	1972	168465	411923.07	0.163822526	2514447.073	14.92563484
3763	PL	2	4	PIPE, PLASTIC,	1973	158850	456376.98	0.170648464	2674369.103	16.83581431
3763	PL	2	4	PIPE, PLASTIC,	1974	209625	576190.99	0.19112628	3014713.573	14.3814601
3763	PL	2	4	PIPE, PLASTIC,	1975	229667	808289.31	0.216723549	3729586.895	16.2391066
3763	PL	2	4	PIPE, PLASTIC,	1976	263209	908548.24	0.230375427	3943772.36	14.98342519
3763	PL	2	4	PIPE, PLASTIC,	1977	288911	903778.55	0.245733788	3677876.599	12.73013696
3763	PL	2	4	PIPE, PLASTIC,	1978	421123	1411770.71	0.264505119	5337404.104	12.67421657
3763	PL	2	4	PIPE, PLASTIC,	1979	364371	1089024.05	0.288395904	3776142.564	10.36345528
3763	PL	2	4	PIPE, PLASTIC,	1980	497103	1699044.48	0.319112628	5324278.424	10.71061415
3763	PL	2	4	PIPE, PLASTIC,	1981	298008	1437203.87	0.348122867	4128438.568	13.85344879
3763	PL	2	4	PIPE, PLASTIC,	1982	194170	1040443.68	0.375426621	2771363.62	14.27287233
3763	PL	2	4	PIPE, PLASTIC,	1983	306364	1659986.35	0.389078498	4266456.145	13.92610145
3763	PL	2	4	PIPE, PLASTIC,	1984	468146	1801885.99	0.397610922	4531781.932	9.680274812
3763	PL	2	4	PIPE, PLASTIC,	1985	424118	1692312.57	0.401023891	4219979.43	9.950012567
3763	PL	2	4	PIPE, PLASTIC,	1986	500807	1951684.16	0.407849829	4785300.911	9.555179762
3763	PL	2	4	PIPE, PLASTIC,	1987	727987	2536681.54	0.419795222	6042664.156	8.300511075
3763	PL	2	4	PIPE, PLASTIC,	1988	805950	3539346.17	0.441979522	8007941.527	9.936027703
3763	PL	2	4	PIPE, PLASTIC,	1989	881633	2925075.71	0.469283276	6233070.422	7.069915058
3763	PL	2	4	PIPE, PLASTIC,	1990	1129519	3583477.44	0.482935154	7420204.169	6.569348695
3763	PL	2	4	PIPE, PLASTIC,	1991	783132	4002366.07	0.493174061	8115524.28	10.36290725
3763	PL	2	4	PIPE, PLASTIC,	1992	919638	3448309.49	0.5	6896618.98	7.49927578
3763	PL	2	4	PIPE, PLASTIC,	1993	1083228	4368541.87	0.511945392	8533218.453	7.877582977

3763	PL	2	4 PIPE, PLASTIC,	1994	1351246	5781028.61	0.523890785	11034797.28	8.16638664
3763	PL	2	4 PIPE, PLASTIC,	1995	1283394	5892149.68	0.534129693	11031308.99	8.595418855
3763	PL	2	4 PIPE, PLASTIC,	1996	1011083	4351674.35	0.54778157	7944178.097	7.857097881
3763	PL	2	4 PIPE, PLASTIC,	1997	1175739	4582255.91	0.558020478	8211626.799	6.98422592
3763	PL	2	4 PIPE, PLASTIC,	1998	1234062	5327855.79	0.571672355	9319771.621	7.552109716
3763	PL	2	4 PIPE, PLASTIC,	1999	1092784	4879424.05	0.581911263	8385168.602	7.67321685
3763	PL	2	4 PIPE, PLASTIC,	2000	1110488	5465824.62	0.593856655	9203946.056	8.288199472
3763	PL	2	4 PIPE, PLASTIC,	2001	1103048	5751160.36	0.602389078	9547252.042	8.655336887
3763	PL	2	4 PIPE, PLASTIC,	2002	1340501	7176563.41	0.610921502	11747112.17	8.763225222
3763	PL	2	4 PIPE, PLASTIC,	2003	1406570	7192195.15	0.629692833	11421751.65	8.120286688
3763	PL	2	4 PIPE, PLASTIC,	2004	1210117	6991259.71	0.645051195	10838302.09	8.956408422
3763	PL	2	4 PIPE, PLASTIC,	2005	1196257	6823319.05	0.682593857	9996162.408	8.35619972
3763	PL	2	4 PIPE, PLASTIC,	2006	1297992	8433896.29	0.721843003	11683837.41	9.001471052
3763	PL	2	4 PIPE, PLASTIC,	2007	784139	5969649.69	0.766211604	7791124.094	9.93589669
3763	PL	2	4 PIPE, PLASTIC,	2008	505351	7077317.58	0.791808874	8938164.013	17.68704131
3763	PL	2	4 PIPE, PLASTIC,	2009	361800	6341148.96	0.841296928	7537349.474	20.83291729
3763	PL	2	4 PIPE, PLASTIC,	2010	309529	6273305.51	0.822525597	7626881.803	24.64028186
3763	PL	2	4 PIPE, PLASTIC,	2011	400651	8127484.35	0.836177474	9719807.814	24.26003633
3763	PL	2	4 PIPE, PLASTIC,	2012	386803	5386947.66	0.875426621	6153511.362	15.90864435
3763	PL	2	4 PIPE, PLASTIC,	2013	501287	6946159.74	0.889078498	7812763.162	15.58540948
3763	PL	2	4 PIPE, PLASTIC,	2014	736472	9062837.54	0.890784983	10173990.04	13.81449673
3763	PL	2	4 PIPE, PLASTIC,	2015	668296	9493864.45	0.90443686	10496989.75	15.70709648
3763	PL	2	4 PIPE, PLASTIC,	2016	638725	10171780.09	0.912969283	11141426.42	17.44322896
3763	PL	2	4 PIPE, PLASTIC,	2017	823452	14240146.13	0.924914676	15396172.75	18.69711016
3763	PL	2	4 PIPE, PLASTIC,	2018	708812	11003751.02	0.938566553	11723996.54	16.54034715
3763	PL	2	4 PIPE, PLASTIC,	2019	822955	18750927	0.964163823	19447864.11	23.63174671
3763	PL	2	4 PIPE, PLASTIC,	2020	671918	16136312.04	0.993174061	16247214.53	24.18035315
3763	PL	3	9 PIPE, PLASTIC,	1968	22474	66392.66	0.133105802	498796.1379	22.19436406
3763	PL	3	9 PIPE, PLASTIC,	1969	45022	154097.83	0.139931741	1101235.712	24.45994651
3763	PL	3	9 PIPE, PLASTIC,	1970	49613	180615.38	0.146757679	1230704.799	24.80609515
3763	PL	3	9 PIPE, PLASTIC,	1971	43585	181384.85	0.156996587	1155342.632	26.50780387
3763	PL	3	9 PIPE, PLASTIC,	1972	94154	330113.15	0.163822526	2015065.686	21.40180647
3763	PL	3	9 PIPE, PLASTIC,	1973	72408	277540.76	0.170648464	1626388.854	22.46145251
3763	PL	3	9 PIPE, PLASTIC,	1974	98555	338801.75	0.19112628	1772659.156	17.98649644
3763	PL	3	9 PIPE, PLASTIC,	1975	61531	258193.02	0.216723549	1191347.321	19.36174157
3763	PL	3	9 PIPE, PLASTIC,	1976	57483	225615.08	0.230375427	979336.5695	17.03697736
3763	PL	3	9 PIPE, PLASTIC,	1977	50950	201170.04	0.245733788	818650.3017	16.06771937
3763	PL	3	9 PIPE, PLASTIC,	1978	65961	288238.94	0.264505119	1089729.154	16.52081008
3763	PL	3	9 PIPE, PLASTIC,	1979	85205	411004.19	0.288395904	1425138.789	16.72599952
3763	PL	3	9 PIPE, PLASTIC,	1980	134155	728574.42	0.319112628	2283126.257	17.01856999

3763	PL	3	9 PIPE, PLASTIC,	1981	82141	611359.65	0.348122867	1756160.563	21.37982936
3763	PL	3	9 PIPE, PLASTIC,	1982	58249	523784.87	0.375426621	1395172.426	23.95186916
3763	PL	3	9 PIPE, PLASTIC,	1983	76435	556785.46	0.389078498	1431036.314	18.72226485
3763	PL	3	9 PIPE, PLASTIC,	1984	140564	1048262.47	0.397610922	2636402.607	18.75588776
3763	PL	3	9 PIPE, PLASTIC,	1985	145897	882941.92	0.401023891	2201719.001	15.09091346
3763	PL	3	9 PIPE, PLASTIC,	1986	150541	884993.04	0.407849829	2169899.253	14.4140085
3763	PL	3	9 PIPE, PLASTIC,	1987	158720	985266.33	0.419795222	2347016.542	14.78715059
3763	PL	3	9 PIPE, PLASTIC,	1988	191905	1237407.81	0.441979522	2799694.891	14.58896272
3763	PL	3	9 PIPE, PLASTIC,	1989	138681	1058972.48	0.469283276	2256574.085	16.27168887
3763	PL	3	9 PIPE, PLASTIC,	1990	171949	1190962.43	0.482935154	2466091.816	14.34199569
3763	PL	3	9 PIPE, PLASTIC,	1991	210813	1600474.99	0.493174061	3245253.786	15.39399271
3763	PL	3	9 PIPE, PLASTIC,	1992	167645	1184425.58	0.5	2368851.16	14.1301629
3763	PL	3	9 PIPE, PLASTIC,	1993	183221	1487693.24	0.511945392	2905960.795	15.86041336
3763	PL	3	9 PIPE, PLASTIC,	1994	276473	1929837.26	0.523890785	3683663.304	13.32377232
3763	PL	3	9 PIPE, PLASTIC,	1995	34286	312536.44	0.534129693	585132.1209	17.06621131
3763	PL	3	9 PIPE, PLASTIC,	1996	44138	369290.25	0.54778157	674156.0327	15.27382375
3763	PL	3	9 PIPE, PLASTIC,	1997	97344	706766.7	0.558020478	1266560.508	13.01118208
3763	PL	3	9 PIPE, PLASTIC,	1998	140121	979867.03	0.571672355	1714036.058	12.23254229
3763	PL	3	9 PIPE, PLASTIC,	1999	113610	1246010.77	0.581911263	2141238.449	18.84727092
3763	PL	3	9 PIPE, PLASTIC,	2000	131661	1345299.96	0.593856655	2265361.427	17.20601717
3763	PL	3	9 PIPE, PLASTIC,	2001	76113	814483.12	0.602389078	1352088.126	17.76422064
3763	PL	3	9 PIPE, PLASTIC,	2002	87064	1302777.76	0.610921502	2132479.797	24.49324402
3763	PL	3	9 PIPE, PLASTIC,	2003	90591	1177392.47	0.629692833	1869788.584	20.63989341
3763	PL	3	9 PIPE, PLASTIC,	2004	71858	1089724.89	0.645051195	1689361.867	23.50972566
3763	PL	3	9 PIPE, PLASTIC,	2005	30892	618261.38	0.682593857	905752.9217	29.31998322
3763	PL	3	9 PIPE, PLASTIC,	2006	46727	901642.77	0.721843003	1249084.31	26.73153231
3763	PL	3	9 PIPE, PLASTIC,	2007	30446	755798.02	0.766211604	986408.9971	32.39864012
3763	PL	3	9 PIPE, PLASTIC,	2008	50369	1269296.41	0.791808874	1603033.828	31.82580214
3763	PL	3	9 PIPE, PLASTIC,	2009	44669	1278567.91	0.841296928	1519758.205	34.02266013
3763	PL	3	9 PIPE, PLASTIC,	2010	30905	1160476.14	0.822525597	1410869.332	45.65181466
3763	PL	3	9 PIPE, PLASTIC,	2011	63233	2758489.13	0.836177474	3298927.817	52.17098377
3763	PL	3	9 PIPE, PLASTIC,	2012	66332	2003941.77	0.875426621	2289103.075	34.50978524
3763	PL	3	9 PIPE, PLASTIC,	2013	101069	3010052.53	0.889078498	3385586.915	33.4977779
3763	PL	3	9 PIPE, PLASTIC,	2014	115260	2977581.6	0.890784983	3342649.076	29.00094635
3763	PL	3	9 PIPE, PLASTIC,	2015	117674	4297194.34	0.90443686	4751237.516	40.37627272
3763	PL	3	9 PIPE, PLASTIC,	2016	136311	4255952.39	0.912969283	4661660.001	34.19870738
3763	PL	3	9 PIPE, PLASTIC,	2017	108110	4118162.38	0.924914676	4452478.145	41.18470211
3763	PL	3	9 PIPE, PLASTIC,	2018	92953	3656730.67	0.938566553	3896080.314	41.91451931
3763	PL	3	9 PIPE, PLASTIC,	2019	124668	6123578.54	0.964163823	6351180.574	50.94475386
3763	PL	3	9 PIPE, PLASTIC,	2020	78817	4300805.25	0.993174061	4330364.049	54.94200552

3763	PL	4	16 PIPE, PLASTIC,	1974	9986	3851.46	0.19112628	20151.38893	2.017964043
3763	PL	4	16 PIPE, PLASTIC,	1976	1320	25438.74	0.230375427	110422.9751	83.65376902
3763	PL	4	16 PIPE, PLASTIC,	1977	1450	12919.31	0.245733788	52574.41431	36.25821676
3763	PL	4	16 PIPE, PLASTIC,	1978	21762	121151.29	0.264505119	458030.0383	21.04724007
3763	PL	4	16 PIPE, PLASTIC,	1979	9253	97127.15	0.288395904	336784.0822	36.39728545
3763	PL	4	16 PIPE, PLASTIC,	1980	29476	230825.94	0.319112628	723336.9029	24.53985964
3763	PL	4	16 PIPE, PLASTIC,	1981	15540	160498.38	0.348122867	461039.4641	29.66791918
3763	PL	4	16 PIPE, PLASTIC,	1982	19844	249162.84	0.375426621	663679.2011	33.44482973
3763	PL	4	16 PIPE, PLASTIC,	1983	23047	297781.93	0.389078498	765351.8025	33.20830488
3763	PL	4	16 PIPE, PLASTIC,	1984	37132	352345.48	0.397610922	886156.4433	23.86503402
3763	PL	4	16 PIPE, PLASTIC,	1985	39148	295808.09	0.401023891	737632.0883	18.84213978
3763	PL	4	16 PIPE, PLASTIC,	1986	74882	625798.49	0.407849829	1534384.582	20.4906998
3763	PL	4	16 PIPE, PLASTIC,	1987	96249	598811.68	0.419795222	1426437.579	14.82028467
3763	PL	4	16 PIPE, PLASTIC,	1988	108380	864173.7	0.441979522	1955234.703	18.04054903
3763	PL	4	16 PIPE, PLASTIC,	1989	227666	1742038.97	0.469283276	3712126.678	16.30514296
3763	PL	4	16 PIPE, PLASTIC,	1990	303573	2305102.76	0.482935154	4773110.309	15.72310551
3763	PL	4	16 PIPE, PLASTIC,	1991	129148	1383350.88	0.493174061	2804995.21	21.71923073
3763	PL	4	16 PIPE, PLASTIC,	1992	151975	1158823.98	0.5	2317647.96	15.2501922
3763	PL	4	16 PIPE, PLASTIC,	1993	157049	1474468.93	0.511945392	2880129.31	18.33904902
3763	PL	4	16 PIPE, PLASTIC,	1994	354450	2473919.05	0.523890785	4722203.789	13.32262319
3763	PL	4	16 PIPE, PLASTIC,	1995	352461	2962651.88	0.534129693	5546690.101	15.73703219
3763	PL	4	16 PIPE, PLASTIC,	1996	184395	1970513.66	0.54778157	3597261.697	19.50845574
3763	PL	4	16 PIPE, PLASTIC,	1997	237578	1729279.7	0.558020478	3098953.835	13.04394277
3763	PL	4	16 PIPE, PLASTIC,	1998	273080	2355974.83	0.571672355	4121197.762	15.09154007
3763	PL	4	16 PIPE, PLASTIC,	1999	267688	2343999.98	0.581911263	4028105.537	15.04776283
3763	PL	4	16 PIPE, PLASTIC,	2000	237618	2653185.86	0.593856655	4467721.017	18.80211523
3763	PL	4	16 PIPE, PLASTIC,	2001	236275	2797424.15	0.602389078	4643882.583	19.65456601
3763	PL	4	16 PIPE, PLASTIC,	2002	283290	3209024.89	0.610921502	5252761.412	18.54199376
3763	PL	4	16 PIPE, PLASTIC,	2003	366543	4177621.21	0.629692833	6634379.483	18.09986682
3763	PL	4	16 PIPE, PLASTIC,	2004	336951	3632454.11	0.645051195	5631264.837	16.71241468
3763	PL	4	16 PIPE, PLASTIC,	2005	250841	2793345.38	0.682593857	4092250.982	16.31412322
3763	PL	4	16 PIPE, PLASTIC,	2006	319090	3707706.36	0.721843003	5136444.272	16.09716466
3763	PL	4	16 PIPE, PLASTIC,	2007	295654	4285506.38	0.766211604	5593110.777	18.91775784
3763	PL	4	16 PIPE, PLASTIC,	2008	206912	3900916.64	0.791808874	4926588.688	23.8100675
3763	PL	4	16 PIPE, PLASTIC,	2009	134555	3375637.33	0.841296928	4012420.843	29.8199312
3763	PL	4	16 PIPE, PLASTIC,	2010	129741	3107572.44	0.822525597	3778085.996	29.1202164
3763	PL	4	16 PIPE, PLASTIC,	2011	177644	5484258.38	0.836177474	6558725.328	36.92061273
3763	PL	4	16 PIPE, PLASTIC,	2012	127174	4538573.97	0.875426621	5184413.931	40.76630389
3763	PL	4	16 PIPE, PLASTIC,	2013	168328	5298773.05	0.889078498	5959848.383	35.40616168
3763	PL	4	16 PIPE, PLASTIC,	2014	220158	6551729.46	0.890784983	7355006.635	33.40785543

3763	PL	4	16	PIPE, PLASTIC,	2015	207443	5916529.24	0.90443686	6541671.952	31.53479246
3763	PL	4	16	PIPE, PLASTIC,	2016	193106	6828359.24	0.912969283	7479286.943	38.73150986
3763	PL	4	16	PIPE, PLASTIC,	2017	157197	7275901.72	0.924914676	7866565.328	50.04271919
3763	PL	4	16	PIPE, PLASTIC,	2018	153242	7872296.69	0.938566553	8387574.292	54.734174
3763	PL	4	16	PIPE, PLASTIC,	2019	227560	15626837.68	0.964163823	16207658.2	71.22366934
3763	PL	4	16	PIPE, PLASTIC,	2020	224109	11779859.97	0.993174061	11860821.21	52.92434131
3763	PL	6	36	PIPE, PLASTIC,	1984	1148	54347.37	0.397610922	136684.8018	119.0634162
3763	PL	6	36	PIPE, PLASTIC,	1998	55875	1004795.67	0.571672355	1757642.575	31.45669038
3763	PL	6	36	PIPE, PLASTIC,	1999	75302	1424784.6	0.581911263	2448456.82	32.51516321
3763	PL	6	36	PIPE, PLASTIC,	2000	88850	1971537.63	0.593856655	3319888.078	37.3650881
3763	PL	6	36	PIPE, PLASTIC,	2001	84944	1903598.39	0.602389078	3160081.18	37.20193516
3763	PL	6	36	PIPE, PLASTIC,	2002	92458	2205846.06	0.610921502	3610686.567	39.05218118
3763	PL	6	36	PIPE, PLASTIC,	2003	129755	2897552.19	0.629692833	4601532.746	35.46324031
3763	PL	6	36	PIPE, PLASTIC,	2004	93345	2180992.58	0.645051195	3381115.481	36.22170958
3763	PL	6	36	PIPE, PLASTIC,	2005	82659	1929049.94	0.682593857	2826058.162	34.18935823
3763	PL	6	36	PIPE, PLASTIC,	2006	118407	2628455.27	0.721843003	3641311.556	30.75250244
3763	PL	6	36	PIPE, PLASTIC,	2008	115182	4918938.25	0.791808874	6212279.773	53.93446695
3763	PL	6	36	PIPE, PLASTIC,	2009	40103	1531415.35	0.841296928	1820303.033	45.39069478
3763	PL	6	36	PIPE, PLASTIC,	2010	51505	1998513.06	0.822525597	2429727.496	47.17459463
3763	PL	6	36	PIPE, PLASTIC,	2011	76735	3955643.42	0.836177474	4730626.621	61.64887757
3763	PL	6	36	PIPE, PLASTIC,	2012	72515	3492682.26	0.875426621	3989691.626	55.01884612
3763	PL	6	36	PIPE, PLASTIC,	2013	55361	3746433.8	0.889078498	4213839.169	76.11566208
3763	PL	6	36	PIPE, PLASTIC,	2014	121448	6829374.94	0.890784983	7666692.94	63.12737089
3763	PL	6	36	PIPE, PLASTIC,	2015	157239	7031757.47	0.90443686	7774735.618	49.44533874
3763	PL	6	36	PIPE, PLASTIC,	2016	97974	6489816.49	0.912969283	7108471.894	72.55467669
3763	PL	6	36	PIPE, PLASTIC,	2017	69707	7469180.55	0.924914676	8075534.691	115.849695
3763	PL	6	36	PIPE, PLASTIC,	2018	66587	6358475.57	0.938566553	6774666.698	101.7415817
3763	PL	6	36	PIPE, PLASTIC,	2019	122471	13073027.49	0.964163823	13558927.63	110.7113327
3763	PL	6	36	PIPE, PLASTIC,	2020	111554	8964710.25	0.993174061	9026323.379	80.91438567
3763	PL	8	64	PIPE, PLASTIC,	2017	40746	7579535.02	0.924914676	8194847.826	201.120302
3763	PL	8	64	PIPE, PLASTIC,	2018	26082	4715847.91	0.938566553	5024521.591	192.6432632
3763	PL	8	64	PIPE, PLASTIC,	2019	21028	3469513.61	0.964163823	3598468.983	171.1274959
3763	PL	12	144	PIPE, PLASTIC,	2013	1640	583356.06	0.889078498	656135.6068	400.0826871
3763	PL	12	144	PIPE, PLASTIC,	2020	3516	1339411.11	0.993174061	1348616.685	383.56561

State of Minnesota
Minnesota Department of Commerce

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case   Date of Request: 12/8/2021
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 12/20/2021

Analyst Requesting Information: Michael Zajicek

Type of Inquiry: Cost of Service

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
DOC 707	Each response must be submitted as a text searchable PDF, unless otherwise directed. Please include the docket number, request number, and respondent name and title on the answers. If your response contains Trade Secret data, please include a public copy. Topic: Cost studies Reference(s): Zarumba Work Papers Customer Connected Distribution Plant A. Please fully explain how the Company derived its Average Service Line Cost per Customer figures in the above reference. As part of this response, please provide any, and all, supporting information in Microsoft Excel format with all links and formulae intact. B. Please fully explain how the Company derived its Average Meter/Install Cost Per Customer figures in the above reference. As part of this response, please provide any, and all, supporting information in Microsoft Excel format with all links and formulae intact. If this information has already been provided in initial testimony or workpapers, or in response to an earlier Department-DER information request, please identify the specific cite(s) or Department-DER information request number(s). **Response:** A. Please refer to DOC 707 Attachment 1. The Company derived its Average Service Line Cost per Customer amounts using the historical average service line installation cost by customer class. For the Residential, C&I Rate A, C&I Rate , and C&I Rate C rate classes, the

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

average service line cost per customer was calculated as the two-year average from 2019 and 2020 of installation cost data consistent with how the costs were determined in prior rate cases. For Small Dual Fuel, Large Firm, and Large Dual Fuel customer classes, the Average Service Line Cost per Customer was calculated as the six-year average from 2015 through 2020 of installation cost data due to the low annual activity level.

B. Please refer to DOC 707 Attachment 2. The Company derived its Average Meter/Install Cost per Customer amounts using the historical average cost per meter and meter installation cost for 2020. Meter and meter installation cost data contained in the Company's plant accounting system was identified as either small or large. The number of small and large meters by rate class were identified and a weighted average replacement cost per meter and meter installation cost was calculated for each rate class. The sum of each rate class's average replacement cost per meter and meter installation cost equals the ("Average Meter/Install Cost per Customer").

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

Docket No. G-008/GR-21-435

CenterPoint Energy Minnesota Gas Response to DOC 707

Attachment 1 - 380 Svc Lines

New Service Lines

		2015 Additions	2015 Pre-CIAC	2015 CIAC	2015 Cost	2015 Avg Cost	2016 Additions	2016 Pre-CIAC	2016 CIAC	2016 Cost	2016 Avg Cost
Residential		5,648	8,874,912	-2,309,187	$6,565,725	$1,162.49	5,455	7,249,172	-1,530,519	$5,718,653	$1,048.33
Commercial - A		106	349,215	-55,283	$293,932	$2,772.94	66	161,192	-22,932	$138,260	$2,094.84
Commercial/Industrial - B		138	426,105	-17,606	$408,499	$2,960.14	110	379,546	-12,310	$367,236	$3,338.51
Commercial/Industrial - C (S & T)		342	1,917,029	-31,722	$1,885,308	$5,512.60	354	1,648,381	-43,134	$1,605,247	$4,534.60
Small Dual Fuel - A	Sales Svc/Trans	13	108,327	-16,390	$91,937	$7,072.07	12	94,086	-18,925	$75,161	$6,263.38
Small Dual Fuel - B	Sales Svc/Trans										
Large Volume	Sales Svc/Trans										
Total Services		6,247			$9,245,401	$1,479.97	5,997			$7,904,556	$ 1,318.09

		2017 Additions	2017 Pre-CIAC	2017 CIAC	2017 Cost	2017 Avg Cost	2018 Additions	2018 Pre-CIAC	2018 CIAC	2018 Cost	2018 Avg Cost
Residential		6,297	9,375,062	-2,244,853	$7,130,209	$1,132.32	6,193	10,649,690	-2,283,038	$8,366,652	$1,350.99
Commercial - A		89	342,976	-54,575	$288,401	$3,240.46	60	188,845	-20,659	$168,186	$2,803.10
Commercial/Industrial - B		98	325,480	-7,679	$317,801	$3,242.87	102	342,941	-22,024	$320,917	$3,146.25
Commercial/Industrial - C (S & T)		292	1,711,284	-17,873	$1,693,411	$5,799.35	317	2,117,348	-35,532	$2,081,815	$6,567.24
Small Dual Fuel - A	Sales Svc/Trans	5	22,242	-6,352	$15,890	$3,178.00	8	37,208	0	$37,208	$4,651.00
Small Dual Fuel - B	Sales Svc/Trans										
Large Volume	Sales Svc/Trans	2	53,558	-58,790	($5,232)	-$2,616.00					
Total Services		6,783			$9,440,480	$1,391.79	6,680			$10,974,778	$ 1,642.93

Docket No. G-008/GR-21-435
CenterPoint Energy Minnesota Gas Response to DOC 707
Attachment 1 - 380 Svc Lines
Page 2 of 2

New Service Lines

		2019 Additions	2019 Pre-CIAC	2019 CIAC	2019 Cost	2019 Avg Cost	2020 Additions	2020 Pre-CIAC	2020 CIAC	2020 Cost	2020 Avg Cost	Hist. Period	Total	Combined	Avg Cost	Weighting
Residential		6015	$9,821,575.07	-$2,040,813.18	$7,780,761.89	$1,293.56	6617	$11,701,499.07	-$2,323,090.75	$9,378,408.32	$1,417.32	2-year	12,632	$17,159,170	$1,358.39	1.00
Commercial - A		66	$369,253.98	-$44,908.00	$324,345.98	$4,914.33	69	$378,873.23	-$61,857.00	$317,016.23	$4,594.44	2-year	135	$641,362	$4,750.83	3.50
Commercial/Industrial - B		95	$416,267.30	-$11,709.60	$404,557.70	$4,258.50	121	$532,560.95	-$23,620.00	$508,940.95	$4,206.12	2-year	216	$913,499	$4,229.16	3.11
Commercial/Industrial - C (S & T)		381	$2,957,182.36	-$251,666.34	$2,705,516.02	$7,101.09	310	$2,801,589.52	-$7,451.94	$2,794,137.58	$9,013.35	2-year	691	$5,499,654	$7,958.98	5.86
Small Dual Fuel - A	Sales Svc/Trans	2	12321.76	-2232	$10,089.76	$5,044.88	4	43582.43	$0.00	$43,582.43	$10,895.61	6-year	44	273,868	$6,224.26	4.58
Small Dual Fuel - B	Sales Svc/Trans	1	16573.8	0	$16,573.80	$16,573.80	2	16326.41	$0.00	$16,326.41	$8,163.21	6-year	3	32,900	$10,966.74	8.07
Large Volume	Sales Svc/Trans	3	133029.47	0	$133,029.47	$44,343.16	1	50485.78	0	$50,485.78	$50,485.78	6-year	6	178,283	$29,713.88	21.87
Total Services		6,563			$11,374,875	$ 1,733.18	7,124			$13,108,898	$ 1,840.10		13,727	$24,698,736	$ 1,799.28	

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case — Date of Request: 12/13/2021
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 12/23/2021

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Financial

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 3001 - S	Subject: 2020 Residential customer data A. Provide the number of Residential customer bills in the Company's Minnesota service area in 2020. B. Provide the amount of Residential customer usage (in therms) in the Company's Minnesota service area in 2020. C. Provide the percentage of Residential customers in the Company's Minnesota service area who utilized Average Monthly Billing in 2020. D. Provide the number of Residential customers in the Company's Minnesota service area who received assistance from the Low Income Home Energy Assistance Program in 2020. **Response:** Parts A and B are consistent with what was provided in the Annual Gas Jurisdictional Report filed on May 1, 2021. A. Residential Gas Bills in 2020 totaled 9,758,646. B. Residential gas usage in 2020 totaled 706,072,000 therms. C. The percentage of Residential customers in 2020 that utilized Average Monthly Billing was 31%. D. 23,723 Residential accounts received a LIHEAP payment in 2020.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

Supplemented 02/1/22:

This response corrects information originally provided in part C. related to the percentage of Residential customers in 2020 that utilized Average Monthly Billing. Upon further review, the Company discovered the response inadvertently included some customers that had dropped out from the budget program. The corrected and accurate percentage of Residential customers in 2020 that utilized Average Monthly Billing was 23%.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case   Date of Request: 1/4/2022
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 1/14/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 3003 - S	Subject: 2020 Residential customer data Complete the following table detailing the distribution of annual gas usage for Residential customers in the Company's Minnesota service area in 2020.

Annual usage (therms)	Number of customers
0 to 87	
88 to 174	
175 to 261	
262 to 348	
349 to 435	
436 to 522	
523 to 609	
610 to 696	
697 to 783	
784 to 870	
871 to 957	

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

958 to 1044	
1045 to 1131	
1132 to 1218	
1219 to 1305	
1306 to 1392	
1393 to 1479	
1480 to 1566	
1567 to 1653	
1654 to 1740	
1741 to 1827	
1828 to 1914	
1915 to 2001	
2002 to 2088	
2089 to 2175	
2176 to 2262	
2263 to 2349	
Over 2,349	

Response:

CenterPoint Energy Minnesota Gas objects to this information request on the grounds and to the extent that it requests information that is not regularly maintained by the Company as requested and, as a result, it requests the Company to engage in new analysis and create reports and compilations that do not presently exist. In addition, CenterPoint Energy Minnesota Gas objects to this information request on the grounds and to the extent that it is unduly burdensome to respond to as stated. Subject to and without waiving this objection, CenterPoint Energy Minnesota Gas provided monthly usage frequency data with number of customers as part of a previous information request response. Please reference DOC 306 submitted on December 27, 2021.

Supplemented 1/20/22:

Please see the table below for information compiled to respond to this request. The response to the request was performed using residential customer data for the year 2020 and only included "Mature Customers." Mature customers are defined as customers with 12 months of usage in 2020. Data for customers with less than 12 months of usage was excluded because it would introduce a bias because a full year of data would not be available.

Annual usage (therms)	**Number of customers**
0 to 87	13,287
88 to 147	11,907
175 to 261	10,696
262 to 348	13,912
349 to 435	23,119
436 to 522	36,835
523 to 609	53,486
610 to 696	68,214
697 to 783	75,250
784 to 870	74,745
871 to 957	67,322
958 to 1044	57,136
1045 to 1131	45,929
1132 to 1218	35,215
1219 to 1305	26,403
1306 to 1392	19,620
1393 to 1479	14,673
1480 to 1566	11,124
1567 to 1653	8,326
1654 to 1740	6,255
1741 to 1827	4,798
1828 to 1914	3,775
1915 to 2001	2,933
2002 to 2088	2,321
2089 to 2175	1,967
2176 to 2262	1,577
2263 to 2349	1,289
Over 2349	8,748

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case — Date of Request: 12/13/2021
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 12/23/2021

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 6001	Subject: Residential Water Heater Program Reference: Berreman Direct, Schedule 2 A. Provide Berreman Direct Schedule 2 in a live Excel spreadsheet with all formulae and links intact. B. Provide the resource(s) used to develop the annual Dth/water heater assumption. **Response:** A. The OAG 6001 – Attachment 1 is the Excel spreadsheet for the Berreman Schedule 2 with all formulae and links intact. B. The annual Dth/water heater is based on using the State of Minnesota Technical Reference Manual, Version 3.0 and by applying the Zone 3 calculations as formulas stated on pages 143 to 146. The following is the link to State of Minnesota Reference Manual, Version 3.0. https://mn.gov/commerce-stat/pdfs/mn-trm-v3.0.pdf

Response By: Todd Berreman
Title: Director, Gas Conservation Imprvmnt Prgrm
Department: Gas Conservation Improvement Prgrm
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case Date of Request: 12/13/2021
Requested From: CenterPoint Energy Minnesota Gas Response Due: 12/23/2021

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 6002	Subject: Foodservice Program Reference: Berreman Direct, Schedule 3 A. Provide Berreman Direct Schedule 3 in a live Excel spreadsheet with all formulae and links intact. B. Provide a narrative description of how the Dth/year assumptions for booster water heaters, dishwashers, and steamers were developed. Provide any resource(s) used in the development of these assumptions. **Response:** A. The OAG 6002 – Attachment 1 is the Excel spreadsheet for the Berreman Schedule 3 with all formulae and links intact. B. The booster water heaters, dishwashers, and steamers are commercial equipment. Their BTU/hr input and annual operating hours varies significantly based on the size of facility and its operating hours. The annual Dth usages of these equipment in Berreman Schedule 3 are based on the BTU/hr input size and operating hours of qualifying customers in previous years.

Response By: Todd Berreman
Title: Director, Gas Conservation Imprvmnt Prgrm
Department: Gas Conservation Improvement Prgrm
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case   Date of Request: 12/13/2021
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 12/23/2021

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 6003	Subject: C&I Market Program Reference: Berreman Direct, Schedule 4 A. Provide Berreman Direct Schedule 4 in a live Excel spreadsheet with all formulae and links intact. B. Provide a narrative description of how the Dth/year assumptions for desiccant dehumidification, gas humidifier, and rooftop heating system were developed. Provide any resource(s) used in the development of these assumptions. **Response:** A. The OAG 6003 – Attachment is the Excel spreadsheet for the Berreman Schedule 4 with all formulae and links intact. B. The desiccant dehumidification, gas humidifier, and rooftop heating system are commercial equipment. Their BTU/hr input annual operating hours varies significantly based on size of the facility and its operating hours. The annual Dth usage of these equipment in Berreman Schedule 4 is based on the BTU/hr input size and operating hours of qualifying customers in previous years.

Response By: Todd Berreman
Title: Director, Gas Conservation Imprvmnt Prgrm
Department: Gas Conservation Improvement Prgrm
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case — Date of Request: 12/13/2021
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 12/23/2021

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Cost of Service

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 7004	Subject: Class cost of service study

Reference: Zarumba Direct, Table 6, page 64

Separately for the Residential and C&I A classes, provide the costs (in $ per customer-month) by FERC account that make up the "Customer-Related Costs" included in Table 6 of Zarumba Direct.

Response:

Please see below table.

	FERC Acc.	Description	$ per Customer-Month	
			Residential	**C&I A**
Plant	374	Land & land rights.	$ 0.01	$ 0.01
	375	Structures and improvements.	$ 0.01	$ 0.01
	376	Mains.	$ 2.52	$ 2.52
	378	Measuring and regulating equipment--General.	$ 0.11	$ 0.11
	380	Services	$ 1.63	$ 5.70
	381	Meters	$ 0.27	$ 0.44
	382/383	Meter Install/ Regulators	$ 0.39	$ 0.64
	397	ERTS	$ 0.09	$ 0.10
	303	Miscellaneous intangible plant.	$ 0.00	$ 0.00

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

		386	Other equipment.	$ (0.00)	$ (0.00)
		389	Land & land rights.	$ 0.00	$ 0.01
		390	Structures and improvements.	$ 0.10	$ 0.18
		391	Office furniture and equipment.	$ 0.14	$ 0.26
		392	Transportation equipment.	$ 0.04	$ 0.07
		393	Stores equipment.	$ 0.00	$ 0.00
		394	Tool, shop and garage equipment.	$ 0.03	$ 0.06
		395	Laboratory Equipment	$ 0.00	$ 0.00
		396	Power operated equipment.	$ 0.01	$ 0.03
		397	Communication w/o ERTS	$ 0.00	$ 0.00
		398.1-398.4	Miscellaneous equipment.	$ 0.00	$ 0.00
		399	Water Treatment	$ 0.00	$ 0.00
	O&M	875	Measuring and regulating station--General.	$ 0.06	$ 0.06
		877	Measuring and regulating station--City gate check stations.	$ 0.00	$ 0.00
		889	Measuring & regulating station equipment--General.	$ 0.04	$ 0.04
		891	Measuring & regulating station equipment--City gates.	$ 0.00	$ 0.00
		874	Mains and services.	$ 0.54	$ 1.07
		887	Mains.	$ 0.21	$ 0.21
		892	Services.	$ 0.36	$ 1.24
		878	Meter and house	$ 0.41	$ 0.67

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

	regulator.		
893	Meters and house regulators.	$ 0.14	$ 0.22
924	Property insurance.	$ 0.20	$ 0.38
932	A&G Maintenance	$ 0.06	$ 0.12
905	Miscellaneous customer accounts expenses	$ 0.03	$ 0.03
902	Meter reading expense.	$ 0.14	$ 0.14
904	Uncollectible accounts.	$ 0.67	$ 0.65
909	Informational and instructional advertising expense	$ 0.09	$ -
903	Customer records and collection expense.	$ 1.30	$ 2.02
879	Customer installations.	$ 0.35	$ 0.55
901	Supervision.	$ 0.00	$ 0.00
910, 918	Miscellaneous customer service and information expense (GAP)	$ 0.00	$ 0.00
909	Informational and instructional advertising expense	$ 0.10	$ 0.20
880	Other.	$ 0.54	$ 1.05
881	Rents.	$ 0.01	$ 0.01
885	Supervision and engineering.	$ 0.01	$ 0.01
894	Other equipment.	$ 0.00	$ 0.01
920	Administrative and general salaries.	$ 0.20	$ 0.33
921	Office supplies and expenses.	$ 0.31	$ 0.51

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
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		922, 923	Outside services employed.	$ 0.02	$ 0.04
		926	Employee pensions and benefits.	$ 0.54	$ 0.89
		925	Injuries and damages.	$ 0.10	$ 0.16
		930.2,930.4	Miscellaneous general expenses, Corporate	$ 0.81	$ 1.33
		931	Rent	$ 0.00	$ 0.01
		928	Regulatory commission expense.	$ 0.10	$ 0.20
		911	Supervision	$ 0.00	$ (0.00)
		912	Demonstrating and selling expense	$ 0.02	$ (0.00)
		913	Advertising expense	$ 0.00	$ -
	Depreciation	375	Structures and improvements.	$ 0.00	$ 0.00
		376	Mains.	$ 2.18	$ 2.80
		378	Measuring and regulating equipment--General.	$ 0.07	$ 0.10
		380	Services.	$ 1.16	$ 4.97
		381	Meters.	$ 0.11	$ 0.22
		382	Meter installations.	$ 0.17	$ 0.34
		390	Structures and improvements.	$ 0.06	$ 0.11
		391	Office furniture and equipment.	$ 0.31	$ 0.58
		392	Transportation equipment.	$ 0.05	$ 0.09
		393	Stores equipment.	$ 0.00	$ 0.00
		394	Tool, shop and garage equipment.	$ 0.03	$ 0.06
		395	Laboratory Equipment	$ 0.00	$ 0.00
		396	Power operated equipment.	$ 0.01	$ 0.02
		397	Communication equipment.	$ 0.00	$ 0.00

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

	397	ERTS	$ 0.20	$ 0.26
	398.1-398.4	Misc Equip	$ 0.00	$ 0.00
	399	Water Treatment	$ 0.00	$ 0.00
Other	Various	Deferred Tax, Customer advances, UGS, Working Capital	$ (0.89)	$ (1.68)
	4081	Taxes Other than Income - payroll	$ 0.16	$ 0.26
	4082	Taxes Other than Income - property	$ 1.73	$ 3.28
	Various (incl. 4090, 4100, 4110)	Income Tax Allowance - PreFiling (Alloc line 4)	$ 0.38	$ 0.71
	na	Income tax on deficiency (Alloc Line 4)	$ 0.69	$ 1.32
	Various	Revenue Credits to the Cost of Service	$ (0.18)	$ (0.35)
Total			$ 18.94	$ 35.35

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case   Date of Request: 1/7/2022
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 1/7/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 7007i	Hi Mr. Zarumba, My name is Andrew Twite, and I am reviewing CenterPoint's Minnesota rate case for the Office of the Attorney General. I have a follow-up question regarding your response to OAG IR 7007 (copied), which requested detail on the costs that are included in FERC accounts 902 and 903. When I asked the same question in CPE's 2019 rate case, Mr. Feingold provided the attached spreadsheet, which was helpful. Does CPE have something similar it could pass along in this case? Or is there anything else y'all could share that would help me get a better understanding of the types of costs that make up those accounts? **Response:** Please see OAG 7007 Attachment 1.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

FERC ACCOUNT 902

			Allocation to Customer Classes												
SubAccount	2020 Base Year	Test Year ended 12/31/2021	Residential Sales Service	A - Sales Service	B - Sales Service	C - Sales Service	C - Transport	Sm Vol Dual Fuel - A - Sales Service	Sm Vol Dual Fuel - A - Transport	Sm Vol Dual Fuel - B - Sales Service	Sm Vol Dual Fuel - B - Transport	Large Firm - Sales Service	Large Firm - Transport	Lg Dual Fuel Sales Service	Lg Dual Fuel Transport
500140 Gas Used in Oper	547.27	576.59	519.05	17.73	12.78	13.26	2.41	7.00	0.53	1.19	0.21	0.18	0.38	1.13	0.77
515040 Sal&Wages Exp-STI-E	29,802.57	31,399.46	28,265.58	965.27	695.84	721.87	131.47	381.04	28.66	64.67	11.23	9.88	20.66	61.53	41.77
515044 Sal&Wages Exp-STI-U	33,983.54	35,804.46	32,230.93	1,100.68	793.46	823.15	149.91	434.49	32.68	73.75	12.80	11.27	23.56	70.16	47.63
515050 Non-prod-Exempt	38,711.10	40,785.34	36,714.67	1,253.80	903.84	937.66	170.77	494.93	37.22	84.01	14.58	12.83	26.84	79.92	54.25
515054 Non-prod-Union	152,669.17	160,849.56	144,795.64	4,944.76	3,564.57	3,697.93	673.48	1,951.92	146.80	331.31	57.52	50.62	105.83	315.20	213.97
515055 Non-prod- OTJ Union	178,616.89	188,187.62	169,405.18	5,785.18	4,170.41	4,326.44	787.94	2,283.67	171.75	387.62	67.29	59.22	123.82	368.78	250.34
515058 Nonprod-OT-OTJ Unio	3,194.06	3,365.21	3,029.33	103.45	74.58	77.37	14.09	40.84	3.07	6.93	1.20	1.06	2.21	6.59	4.48
517988 Other Comp-Union	4,033.36	4,249.48	3,825.35	130.64	94.17	97.70	17.79	51.57	3.88	8.75	1.52	1.34	2.80	8.33	5.65
517989 OT Union - Double	9.90	10.43	9.39	0.32	0.23	0.24	0.04	0.13	0.01	0.02	0.00	0.00	0.01	0.02	0.01
517990 Overtime Union-1.5X	1,246.94	1,313.75	1,182.63	40.39	29.11	30.20	5.50	15.94	1.20	2.71	0.47	0.41	0.86	2.57	1.75
517991 Regular Union	546,562.47	575,848.63	518,374.89	17,702.47	12,761.32	13,238.77	2,411.08	6,987.97	525.54	1,186.10	205.92	181.21	378.89	1,128.44	766.02
517996 Other Comp-Exempt	737.98	777.52	699.92	23.90	17.23	17.88	3.26	9.44	0.71	1.60	0.28	0.24	0.51	1.52	1.03
517999 Regular Exempt	203,671.90	214,585.14	193,168.04	6,596.68	4,755.40	4,933.32	898.47	2,604.01	195.84	441.99	76.73	67.53	141.19	420.50	285.45
522060 Business Meals	195.51	205.99	185.43	6.33	4.56	4.74	0.86	2.50	0.19	0.42	0.07	0.06	0.14	0.40	0.27
522080 Park/In-town Travel	9.50	10.01	9.01	0.31	0.22	0.23	0.04	0.12	0.01	0.02	0.00	0.00	0.01	0.02	0.01
522110 Occ Hlth & Safety	1,729.35	1,822.01	1,640.16	56.01	40.38	41.89	7.63	22.11	1.66	3.75	0.65	0.57	1.20	3.57	2.42
522120 Books & Subscripton	13.62	14.35	12.92	0.44	0.32	0.33	0.06	0.17	0.01	0.03	0.01	0.00	0.01	0.03	0.02
522130 Misc Empl Rel Exp	5,522.07	5,817.96	5,237.28	178.85	128.93	133.75	24.36	70.60	5.31	11.98	2.08	1.83	3.83	11.40	7.74
523000 Empl Reimburs/Deduc	(195.96)	(206.46)	(185.85)	(6.35)	(4.58)	(4.75)	(0.86)	(2.51)	(0.19)	(0.43)	(0.07)	(0.06)	(0.14)	(0.40)	(0.27)
530010 M&S - Non Inv	4,294.92	4,525.05	4,073.42	139.11	100.28	104.03	18.95	54.91	4.13	9.32	1.62	1.42	2.98	8.87	6.02
530020 M&S-Stores,Tools	1,340.35	1,412.17	1,271.22	43.41	31.29	32.47	5.91	17.14	1.29	2.91	0.50	0.44	0.93	2.77	1.88
530999 M&S-Inventory Issue	1,371.00	1,444.46	1,300.29	44.40	32.01	33.21	6.05	17.53	1.32	2.98	0.52	0.45	0.95	2.83	1.92
531020 Motor-Veh & Plt	32.12	33.84	30.46	1.04	0.75	0.78	0.14	0.41	0.03	0.07	0.01	0.01	0.02	0.07	0.05
531030 Purch Veh Fuel Exp	5.33	5.62	5.06	0.17	0.12	0.13	0.02	0.07	0.01	0.01	0.00	0.00	0.00	0.01	0.01
532020 M&S Exp-Equipment	86.71	91.36	82.24	2.81	2.02	2.10	0.38	1.11	0.08	0.19	0.03	0.03	0.06	0.18	0.12
532040 M&S-Misc	74.30	78.28	70.47	2.41	1.73	1.80	0.33	0.95	0.07	0.16	0.03	0.02	0.05	0.15	0.10
533010 Purch-Comp Hdware	61.31	64.60	58.15	1.99	1.43	1.49	0.27	0.78	0.06	0.13	0.02	0.02	0.04	0.13	0.09
533020 Pur-Comp Sftw & Upg	1.04	1.10	0.99	0.03	0.02	0.03	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
535010 Office Supplies	364.89	384.44	346.07	11.82	8.52	8.84	1.61	4.67	0.35	0.79	0.14	0.12	0.25	0.75	0.51
540040 Meter & Svcing Svcs	214,436.76	225,926.81	203,377.73	6,945.34	5,006.74	5,194.06	945.95	2,741.64	206.19	465.35	80.79	71.10	148.65	442.73	300.54
540050 Construction Svcs	23.13	24.37	21.94	0.75	0.54	0.56	0.10	0.30	0.02	0.05	0.01	0.01	0.02	0.05	0.03
540080 Billable Cntrctd Lb	48,058.30	50,633.38	45,579.81	1,556.55	1,122.08	1,164.06	212.00	614.44	46.21	104.29	18.11	15.93	33.32	99.22	67.36
541530 Motor Veh Reg/Lic	15.00	15.80	14.23	0.49	0.35	0.36	0.07	0.19	0.01	0.03	0.01	0.00	0.01	0.03	0.02
543010 Prof Serv-Ded	157.45	165.89	149.33	5.10	3.68	3.81	0.69	2.01	0.15	0.34	0.06	0.05	0.11	0.33	0.22
543050 Technical Services	323.62	340.96	306.93	10.48	7.56	7.84	1.43	4.14	0.31	0.70	0.12	0.11	0.22	0.67	0.45
543090 Wireless Services	8,539.20	8,996.75	8,098.81	276.57	199.38	206.84	37.67	109.18	8.21	18.53	3.22	2.83	5.92	17.63	11.97
543160 Reimburseable Costs	1,150.50	1,212.15	1,091.17	37.26	26.86	27.87	5.08	14.71	1.11	2.50	0.43	0.38	0.80	2.38	1.61
545040 Cont/Sv Add/Alt/Rem	19.33	20.37	18.33	0.63	0.45	0.47	0.09	0.25	0.02	0.04	0.01	0.01	0.01	0.04	0.03
545045 Cont/Sv -Bldg Mnt	2,297.72	2,420.84	2,179.22	74.42	53.65	55.66	10.14	29.38	2.21	4.99	0.87	0.76	1.59	4.74	3.22
545060 Cont/Sv Elev Serv	2.88	3.03	2.73	0.09	0.07	0.07	0.01	0.04	0.00	0.01	0.00	0.00	0.00	0.01	0.00
545070 Cont/Sv Jan Serv	4,622.58	4,870.27	4,384.18	149.72	107.93	111.97	20.39	59.10	4.44	10.03	1.74	1.53	3.20	9.54	6.48
545080 Cont/Sv Pest Cont	177.48	186.99	168.33	5.75	4.14	4.30	0.78	2.27	0.17	0.39	0.07	0.06	0.12	0.37	0.25
545090 Cont/Sv Sec Elect	1,103.53	1,162.66	1,046.62	35.74	25.77	26.73	4.87	14.11	1.06	2.39	0.42	0.37	0.76	2.28	1.55
545100 Cont/Sv Sec Owned	6.16	6.49	5.84	0.20	0.14	0.15	0.03	0.08	0.01	0.01	0.00	0.00	0.00	0.01	0.01
545105 Cont/Sv Trash Rem	1,074.42	1,131.99	1,019.01	34.80	25.09	26.02	4.74	13.74	1.03	2.33	0.40	0.36	0.74	2.22	1.51
545110 Cont/Sv Landscap	4,075.18	4,293.54	3,865.01	131.99	95.15	98.71	17.98	52.10	3.92	8.84	1.54	1.35	2.83	8.41	5.71
545115 Cont/Sv A/C / Heat	3,174.14	3,344.22	3,010.44	102.81	74.11	76.88	14.00	40.58	3.05	6.89	1.20	1.05	2.20	6.55	4.45
545160 Software Maintenanc	84,400.75	88,923.15	80,048.00	2,733.63	1,970.62	2,044.35	372.32	1,079.09	81.15	183.16	31.80	27.98	58.51	174.26	118.29
550020 Misc Adm Expenses	7,128.77	7,510.75	6,761.12	230.89	166.44	172.67	31.45	91.14	6.85	15.47	2.69	2.36	4.94	14.72	9.99
550040 Postage/Courier	84.08	88.59	79.74	2.72	1.96	2.04	0.37	1.07	0.08	0.18	0.03	0.03	0.06	0.17	0.12
550041 Courier Expense	157.48	165.92	149.36	5.10	3.68	3.81	0.69	2.01	0.15	0.34	0.06	0.05	0.11	0.33	0.22
550100 A & G Exp-Freight	0.28	0.30	0.27	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
571010 Utilities-Electrici	4,327.23	4,559.09	4,104.06	140.15	101.03	104.81	19.09	55.33	4.16	9.39	1.63	1.43	3.00	8.93	6.06
571040 Utilities-Water	1,947.59	2,051.95	1,847.15	63.08	45.47	47.17	8.59	24.90	1.87	4.23	0.73	0.65	1.35	4.02	2.73

FERC ACCOUNT 902

			Allocation to Customer Classes												
SubAccount	**2020 Base Year**	**Test Year ended 12/31/2021**	**Residential Sales Service**	**A - Sales Service**	**B - Sales Service**	**C - Sales Service**	**C - Transport**	**Sm Vol Dual Fuel - A - Sales Service**	**Sm Vol Dual Fuel - A - Transport**	**Sm Vol Dual Fuel - B - Sales Service**	**Sm Vol Dual Fuel - B - Transport**	**Large Firm - Sales Service**	**Large Firm - Transport**	**Lg Dual Fuel Sales Service**	**Lg Dual Fuel Transport**
571050 Utilities Exp-Other	335.79	353.78	318.47	10.88	7.84	8.13	1.48	4.29	0.32	0.73	0.13	0.11	0.23	0.69	0.47
641002 Stores Overhead	41.38	43.60	39.25	1.34	0.97	1.00	0.18	0.53	0.04	0.09	0.02	0.01	0.03	0.09	0.06
641003 Transportation OH	193.68	204.06	183.69	6.27	4.52	4.69	0.85	2.48	0.19	0.42	0.07	0.06	0.13	0.40	0.27
641005 Stores Overhead -Qt	0.75	0.79	0.71	0.02	0.02	0.02	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
642087 Office Rent	(1,459.20)	(1,537.39)	(1,383.95)	(47.26)	(34.07)	(35.34)	(6.44)	(18.66)	(1.40)	(3.17)	(0.55)	(0.48)	(1.01)	(3.01)	(2.05)
642608 BU Labor	52,247.41	55,046.95	49,552.88	1,692.23	1,219.89	1,265.53	230.48	668.00	50.24	113.38	19.68	17.32	36.22	107.87	73.23
642620 BU Non Labor Other	22,945.94	24,175.44	21,762.56	743.19	535.75	555.79	101.22	293.37	22.06	49.80	8.65	7.61	15.91	47.37	32.16
643001 Un labor-ST-IntAllo	(278,822.35)	(293,762.34)	(264,442.79)	(9,030.70)	(6,510.04)	(6,753.60)	(1,229.98)	(3,564.83)	(268.10)	(605.08)	(105.05)	(92.44)	(193.29)	(575.66)	(390.78)
643002 Un Labor 1 1/2-IntA	(17.24)	(18.16)	(16.35)	(0.56)	(0.40)	(0.42)	(0.08)	(0.22)	(0.02)	(0.04)	(0.01)	(0.01)	(0.01)	(0.04)	(0.02)
643003 Un Labor-DBL-Int Ac	395.22	416.40	374.84	12.80	9.23	9.57	1.74	5.05	0.38	0.86	0.15	0.13	0.27	0.82	0.55
643502 Fleet Pool Vehicles	26,780.00	28,214.94	25,398.89	867.37	625.27	648.66	118.14	342.39	25.75	58.12	10.09	8.88	18.56	55.29	37.53
722150 Property Tax	13,617.84	14,347.52	12,915.53	441.06	317.95	329.85	60.07	174.11	13.09	29.55	5.13	4.51	9.44	28.12	19.09
9020 Meter Reading Exp	**1,432,255.99**	**1,508,999.79**	**1,358,391.02**	**46,388.96**	**33,440.78**	**34,691.94**	**6,318.18**	**18,311.84**	**1,377.15**	**3,108.15**	**539.61**	**474.86**	**992.88**	**2,957.06**	**2,007.35**

FERC ACCOUNT 903

SubAccount	2020 Base Year	Test Year ended 12/31/2022	Allocation to Customer Classes: Residential Sales Service	A - Sales Service	B - Sales Service	C - Sales Service	C - Transport	Sm Vol Dual Fuel - A - Sales Service	Sm Vol Dual Fuel - A - Transport	Sm Vol Dual Fuel - B - Sales Service	Sm Vol Dual Fuel - B - Transport	Large Firm - Sales Service	Large Firm - Transport	Lg Dual Fuel Sales Service	Lg Dual Fuel Transport
500140 Gas Used in Oper	1,207.80	1,161.50	757.25	40.22	51.51	186.84	4.02	5.81	0.44	2.99	0.52	4.44	63.86	16.50	27.11
508010 Merchandise Exp	48.57	46.71	30.45	1.62	2.07	7.51	0.16	0.23	0.02	0.12	0.02	0.18	2.57	0.66	1.09
515040 Sal&Wages Exp-STI-E	42,606.29	40,973.06	26,712.63	1,418.88	1,817.18	6,590.96	141.92	204.88	15.41	105.40	18.30	156.64	2,252.63	581.90	956.35
515042 Sal&Wages Exp-STI-N	130.89	125.87	82.06	4.36	5.58	20.25	0.44	0.63	0.05	0.32	0.06	0.48	6.92	1.79	2.94
515044 Sal&Wages Exp-STI-U	8,505.57	8,179.53	5,332.69	283.25	362.77	1,315.76	28.33	40.90	3.08	21.04	3.65	31.27	449.70	116.17	190.92
515050 Non-prod-Exempt	33,342.46	32,064.34	20,904.53	1,110.37	1,422.08	5,157.89	111.06	160.34	12.06	82.48	14.32	122.58	1,762.84	455.38	748.41
515052 Non-prod-Non-Exempt	307.68	295.89	192.90	10.25	13.12	47.60	1.02	1.48	0.11	0.76	0.13	1.13	16.27	4.20	6.91
515054 Non-prod-Union	57,828.59	55,611.85	36,256.46	1,925.81	2,466.42	8,945.76	192.63	278.08	20.91	143.05	24.84	212.60	3,057.45	789.80	1,298.03
515055 Non-prod- OTJ Union	43,619.79	41,947.71	27,348.05	1,452.63	1,860.41	6,747.74	145.30	209.76	15.78	107.90	18.73	160.37	2,306.21	595.74	979.09
515058 Nonprod-OT-OTJ Unio	317.65	305.47	199.16	10.58	13.55	49.14	1.06	1.53	0.11	0.79	0.14	1.17	16.79	4.34	7.13
515070 Severance	48,244.41	46,395.06	30,247.53	1,606.64	2,057.65	7,463.14	160.70	232.00	17.45	119.34	20.72	177.37	2,550.72	658.90	1,082.90
515080 Other Compensation	15,981.45	15,368.83	10,019.80	532.21	681.62	2,472.24	53.23	76.85	5.78	39.53	6.86	58.76	844.95	218.27	358.72
517988 Other Comp-Union	711.19	683.93	445.89	23.68	30.33	110.02	2.37	3.42	0.26	1.76	0.31	2.61	37.60	9.71	15.96
517989 OT Union - Double	4,913.03	4,724.70	3,080.29	163.61	209.54	760.02	16.37	23.63	1.78	12.15	2.11	18.06	259.76	67.10	110.28
517990 Overtime Union-1.5X	8,221.50	7,906.35	5,154.59	273.79	350.65	1,271.82	27.39	39.54	2.97	20.34	3.53	30.23	434.68	112.29	184.54
517991 Regular Union	114,978.37	110,570.90	72,087.34	3,829.02	4,903.89	17,786.51	383.00	552.90	41.58	284.42	49.38	422.71	6,079.00	1,570.32	2,580.82
517992 Oth Comp-Non-Exempt	12.53	12.05	7.86	0.42	0.53	1.94	0.04	0.06	0.00	0.03	0.01	0.05	0.66	0.17	0.28
517994 OT Non-Exmpt(1.5)	0.18	0.17	0.11	0.01	0.01	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
517995 Regular Non-Exempt	1,451.80	1,396.15	910.23	48.35	61.92	224.59	4.84	6.98	0.53	3.59	0.62	5.34	76.76	19.83	32.59
517996 Other Comp-Exempt	1,269.60	1,220.93	795.99	42.28	54.15	196.40	4.23	6.11	0.46	3.14	0.55	4.67	67.12	17.34	28.50
517998 Overtime Exempt	20.58	19.79	12.90	0.69	0.88	3.18	0.07	0.10	0.01	0.05	0.01	0.08	1.09	0.28	0.46
517999 Regular Exempt	219,535.53	211,120.07	137,640.95	7,310.98	9,363.32	33,960.93	731.28	1,055.69	79.40	543.07	94.28	807.11	11,607.03	2,998.32	4,927.72
518020 Medical	7,194.00	6,918.23	4,510.38	239.57	306.83	1,112.87	23.96	34.59	2.60	17.80	3.09	26.45	380.35	98.25	161.48
522010 Employee Travel	936.01	900.13	586.84	31.17	39.92	144.80	3.12	4.50	0.34	2.32	0.40	3.44	49.49	12.78	21.01
522020 Training	2,366.67	2,275.95	1,483.82	78.81	100.94	366.11	7.88	11.38	0.86	5.85	1.02	8.70	125.13	32.32	53.12
522030 Registration	1,350.70	1,298.92	846.84	44.98	57.61	208.95	4.50	6.50	0.49	3.34	0.58	4.97	71.41	18.45	30.32
522040 Dues & Licenses	63.75	61.31	39.97	2.12	2.72	9.86	0.21	0.31	0.02	0.16	0.03	0.23	3.37	0.87	1.43
522060 Business Meals	2,416.51	2,323.88	1,515.07	80.47	103.07	373.82	8.05	11.62	0.87	5.98	1.04	8.88	127.76	33.00	54.24
522062 Entertainment	6,996.81	6,728.60	4,386.75	233.01	298.42	1,082.37	23.31	33.65	2.53	17.31	3.00	25.72	369.93	95.56	157.05
522070 Education Exp	555.72	534.42	348.42	18.51	23.70	85.97	1.85	2.67	0.20	1.37	0.24	2.04	29.38	7.59	12.47
522080 Park/In-town Travel	3,423.10	3,291.88	2,146.16	114.00	146.00	529.53	11.40	16.46	1.24	8.47	1.47	12.58	180.98	46.75	76.84
522090 Awards/Gifts	8.29	7.97	5.20	0.28	0.35	1.28	0.03	0.04	0.00	0.02	0.00	0.03	0.44	0.11	0.19
522100 Empl Reloc/Moving	283.47	272.60	177.73	9.44	12.09	43.85	0.94	1.36	0.10	0.70	0.12	1.04	14.99	3.87	6.36
522110 Occ Hlth & Safety	947.51	911.19	594.05	31.55	40.41	146.57	3.16	4.56	0.34	2.34	0.41	3.48	50.10	12.94	21.27
522120 Books & Subscripton	787.54	757.35	493.76	26.23	33.59	121.83	2.62	3.79	0.28	1.95	0.34	2.90	41.64	10.76	17.68
522130 Misc Empl Rel Exp	893.82	859.56	560.39	29.77	38.12	138.27	2.98	4.30	0.32	2.21	0.38	3.29	47.26	12.21	20.06
523000 Empl Reimburs/Deduc	196.14	188.62	122.97	6.53	8.37	30.34	0.65	0.94	0.07	0.49	0.08	0.72	10.37	2.68	4.40
530010 M&S - Non Inv	56,438.46	54,275.00	35,384.90	1,879.52	2,407.13	8,730.72	188.00	271.40	20.41	139.61	24.24	207.49	2,983.95	770.81	1,266.82
530020 M&S-Stores,Tools	56,692.68	54,519.48	35,544.29	1,887.98	2,417.98	8,770.04	188.85	272.62	20.50	140.24	24.35	208.43	2,997.39	774.28	1,272.53
530030 M&S-Ofc Furn & Equi	2,676.38	2,573.79	1,677.99	89.13	114.15	414.02	8.92	12.87	0.97	6.62	1.15	9.84	141.50	36.55	60.07
530999 M&S-Inventory Issue	306,638.34	294,883.97	192,251.31	10,211.68	13,078.30	47,435.25	1,021.42	1,474.55	110.90	758.53	131.69	1,127.34	16,212.23	4,187.93	6,882.84
531020 Motor-Veh & Plt	0.31	0.30	0.19	0.01	0.01	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.01
531030 Purch Veh Fuel Exp	49.56	47.66	31.07	1.65	2.11	7.67	0.17	0.24	0.02	0.12	0.02	0.18	2.62	0.68	1.11
532020 M&S Exp-Equipment	97.26	93.53	60.98	3.24	4.15	15.05	0.32	0.47	0.04	0.24	0.04	0.36	5.14	1.33	2.18
532040 M&S-Misc	(63.06)	(60.64)	(39.54)	(2.10)	(2.69)	(9.76)	(0.21)	(0.30)	(0.02)	(0.16)	(0.03)	(0.23)	(3.33)	(0.86)	(1.42)
533010 Purch-Comp Hdware	56.90	54.72	35.67	1.89	2.43	8.80	0.19	0.27	0.02	0.14	0.02	0.21	3.01	0.78	1.28
533020 Pur-Comp Sftw & Upg	10,577.73	10,172.25	6,631.86	352.26	451.15	1,636.32	35.23	50.87	3.83	26.17	4.54	38.89	559.25	144.47	237.43
535010 Office Supplies	978.63	941.12	613.57	32.59	41.74	151.39	3.26	4.71	0.35	2.42	0.42	3.60	51.74	13.37	21.97
540020 Eng & Tech Services	1,987.38	1,911.20	1,246.02	66.18	84.76	307.44	6.62	9.56	0.72	4.92	0.85	7.31	105.07	27.14	44.61
540040 Meter & Svcing Svcs	556.60	535.26	348.97	18.54	23.74	86.10	1.85	2.68	0.20	1.38	0.24	2.05	29.43	7.60	12.49
540050 Construction Svcs	63.99	61.54	40.12	2.13	2.73	9.90	0.21	0.31	0.02	0.16	0.03	0.24	3.38	0.87	1.44
540080 Billable Cntrctd Lb	1,391,864.55	1,338,510.21	872,649.46	46,351.94	59,363.83	215,313.71	4,636.34	6,693.13	503.37	3,443.06	597.75	5,117.13	73,589.04	19,009.48	31,241.95
540090 Maint Serv-Environm	84,130.89	80,905.90	52,747.07	2,801.73	3,588.23	13,014.58	280.24	404.56	30.43	208.11	36.13	309.30	4,448.07	1,149.02	1,888.41
543010 Prof Serv-Ded	11,545.74	11,103.16	7,238.77	384.50	492.43	1,786.06	38.46	55.52	4.18	28.56	4.96	42.45	610.43	157.69	259.16
543040 Admin Services	11,166.31	10,738.27	7,000.88	371.86	476.25	1,727.37	37.20	53.70	4.04	27.62	4.80	41.05	590.37	152.50	250.64
543050 Technical Services	7,088.44	6,816.72	4,444.20	236.06	302.33	1,096.54	23.61	34.09	2.56	17.53	3.04	26.06	374.77	96.81	159.11
543060 Training Services	84.00	80.78	52.67	2.80	3.58	12.99	0.28	0.40	0.03	0.21	0.04	0.31	4.44	1.15	1.89
543090 Wireless Services	13,075.25	12,574.04	8,197.72	435.43	557.67	2,022.67	43.55	62.88	4.73	32.34	5.62	48.07	691.30	178.58	293.49
543160 Reimburseable Costs	(76.91)	(73.96)	(48.22)	(2.56)	(3.28)	(11.90)	(0.26)	(0.37)	(0.03)	(0.19)	(0.03)	(0.28)	(4.07)	(1.05)	(1.73)
545040 Cont/Sv Add/Alt/Rem	500.74	481.55	313.95	16.68	21.36	77.46	1.67	2.41	0.18	1.24	0.22	1.84	26.47	6.84	11.24
545045 Cont/Sv -Bldg Mnt	19,653.48	18,900.10	12,322.03	654.50	838.23	3,040.28	65.47	94.51	7.11	48.62	8.44	72.26	1,039.10	268.42	441.14
545060 Cont/Sv Elev Serv	2,625.64	2,524.99	1,646.18	87.44	111.99	406.17	8.75	12.63	0.95	6.50	1.13	9.65	138.82	35.86	58.94

545070 Cont/Sv Jan Serv	53,895.51	51,829.53	33,790.56	1,794.83	2,298.67	8,337.34	179.53	259.17	19.49	133.32	23.15	198.14	2,849.50	736.08	1,209.74
545080 Cont/Sv Pest Cont	489.28	470.52	306.76	16.29	20.87	75.69	1.63	2.35	0.18	1.21	0.21	1.80	25.87	6.68	10.98
545090 Cont/Sv Sec Elect	3,799.89	3,654.23	2,382.40	126.54	162.07	587.82	12.66	18.27	1.37	9.40	1.63	13.97	200.90	51.90	85.29
545100 Cont/Sv Sec Owned	48,510.78	46,651.22	30,414.53	1,615.51	2,069.01	7,504.35	161.59	233.28	17.54	120.00	20.83	178.35	2,564.81	662.54	1,088.88
545105 Cont/Sv Trash Rem	3,730.67	3,587.66	2,339.00	124.24	159.12	577.11	12.43	17.94	1.35	9.23	1.60	13.72	197.24	50.95	83.74
545110 Cont/Sv Landscap	1,646.91	1,583.78	1,032.55	54.85	70.24	254.77	5.49	7.92	0.60	4.07	0.71	6.05	87.07	22.49	36.97
545115 Cont/Sv A/C / Heat	3,447.89	3,315.72	2,161.70	114.82	147.05	533.37	11.49	16.58	1.25	8.53	1.48	12.68	182.29	47.09	77.39
545120 Temp Manpower Svc	2,282.46	2,194.97	1,431.02	76.01	97.35	353.08	7.60	10.98	0.83	5.65	0.98	8.39	120.68	31.17	51.23
545150 Printing Svcs	312,602.94	300,619.93	195,990.90	10,410.32	13,332.70	48,357.94	1,041.29	1,503.23	113.05	773.29	134.25	1,149.27	16,527.58	4,269.40	7,016.72
545160 Software Maintenanc	35,524.00	34,162.26	22,272.28	1,183.02	1,515.12	5,495.37	118.33	170.83	12.85	87.88	15.26	130.60	1,878.18	485.17	797.38
545170 Hardware Maintenanc	102,026.23	98,115.26	63,966.81	3,397.68	4,351.48	15,782.89	339.85	490.62	36.90	252.38	43.82	375.09	5,394.21	1,393.43	2,290.09
545520 Long Distance/Fax	266.32	256.11	166.97	8.87	11.36	41.20	0.89	1.28	0.10	0.66	0.11	0.98	14.08	3.64	5.98
546010 Other Services	18,078.92	17,385.90	11,334.84	602.07	771.08	2,796.71	60.22	86.94	6.54	44.72	7.76	66.47	955.85	246.91	405.80
550020 Misc Adm Expenses	(672,752.65)	(646,964.02)	(421,791.93)	(22,404.04)	(28,693.29)	(104,071.10)	(2,240.96)	(3,235.10)	(243.30)	(1,664.19)	(288.92)	(2,473.34)	(35,569.00)	(9,188.16)	(15,100.68)
550040 Postage/Courier	1,626.96	1,564.59	1,020.05	54.18	69.39	251.68	5.42	7.82	0.59	4.02	0.70	5.98	86.02	22.22	36.52
550041 Courier Expense	13,495.26	12,977.95	8,461.05	449.42	575.58	2,087.64	44.95	64.90	4.88	33.38	5.80	49.61	713.51	184.31	302.92
550050 Bank Charges & Fees	1,044.72	1,004.67	655.00	34.79	44.56	161.61	3.48	5.02	0.38	2.58	0.45	3.84	55.24	14.27	23.45
550060 Filing Fees	1,868.47	1,796.85	1,171.46	62.22	79.69	289.04	6.22	8.99	0.68	4.62	0.80	6.87	98.79	25.52	41.94
550086 Member Dues in Orgn	610.00	586.62	382.45	20.31	26.02	94.36	2.03	2.93	0.22	1.51	0.26	2.24	32.25	8.33	13.69
550087 Dues-Industry	7.65	7.36	4.80	0.25	0.33	1.18	0.03	0.04	0.00	0.02	0.00	0.03	0.40	0.10	0.17
550100 A & G Exp-Freight	117.66	113.15	73.77	3.92	5.02	18.20	0.39	0.57	0.04	0.29	0.05	0.43	6.22	1.61	2.64
559994 Cont in Aid of Cons	(82,295.00)	(79,140.39)	(51,596.03)	(2,740.59)	(3,509.93)	(12,730.58)	(274.13)	(395.74)	(29.76)	(203.57)	(35.34)	(302.55)	(4,351.01)	(1,123.95)	(1,847.20)
562016 Affordability Disc	(215,806.00)	(207,533.51)	(135,302.67)	(7,186.78)	(9,204.25)	(33,383.99)	(718.86)	(1,037.76)	(78.05)	(533.84)	(92.68)	(793.40)	(11,409.84)	(2,947.38)	(4,844.01)
562017 Afford Arrears Forg	(50,741.29)	(48,796.22)	(31,812.98)	(1,689.79)	(2,164.15)	(7,849.40)	(169.02)	(244.00)	(18.35)	(125.52)	(21.79)	(186.55)	(2,682.73)	(693.00)	(1,138.94)
562030 Guarant Serv Lvl Pa	27.45	26.40	17.21	0.91	1.17	4.25	0.09	0.13	0.01	0.07	0.01	0.10	1.45	0.37	0.62
562140 Advertising-Gen	6,339.49	6,096.48	3,974.63	211.12	270.38	980.68	21.12	30.49	2.29	15.68	2.72	23.31	335.17	86.58	142.30
562160 Postage-Cust Bills	2,331,875.63	2,242,487.84	1,462,002.90	77,656.23	99,455.85	360,728.20	7,767.55	11,213.41	843.33	5,768.37	1,001.45	8,573.03	123,288.22	31,847.74	52,341.55
562170 Uniforms	3,520.90	3,385.93	2,207.48	117.25	150.17	544.66	11.73	16.93	1.27	8.71	1.51	12.94	186.15	48.09	79.03
565010 Repairs & Maintenan	178.27	171.44	111.77	5.94	7.60	27.58	0.59	0.86	0.06	0.44	0.08	0.66	9.43	2.43	4.00
565040 Rep & Maint-Vehicle	8.73	8.40	5.47	0.29	0.37	1.35	0.03	0.04	0.00	0.02	0.00	0.03	0.46	0.12	0.20
566030 Sponsorships/Contri	818.00	786.64	512.86	27.24	34.89	126.54	2.72	3.93	0.30	2.02	0.35	3.01	43.25	11.17	18.36
571010 Utilities-Electrici	21,020.94	20,215.14	13,179.38	700.04	896.56	3,251.82	70.02	101.08	7.60	52.00	9.03	77.28	1,111.39	287.09	471.84
571020 Util-Land-Phones Ci	1,846.49	1,775.71	1,157.68	61.49	78.75	285.64	6.15	8.88	0.67	4.57	0.79	6.79	97.63	25.22	41.45
571040 Utilities-Water	1,510.62	1,452.71	947.10	50.31	64.43	233.68	5.03	7.26	0.55	3.74	0.65	5.55	79.87	20.63	33.91
571050 Utilities Exp-Other	31,298.14	30,098.39	19,622.82	1,042.29	1,334.88	4,841.65	104.26	150.50	11.32	77.42	13.44	115.07	1,654.76	427.46	702.52
572040 Rental Exp - Other	6,304.14	6,062.48	3,952.47	209.94	268.88	975.22	21.00	30.32	2.28	15.59	2.71	23.18	333.31	86.10	141.50
583005 Construction OH	140.07	134.70	87.82	4.66	5.97	21.67	0.47	0.67	0.05	0.35	0.06	0.51	7.41	1.91	3.14
641002 Stores Overhead	19,114.90	18,382.17	11,984.36	636.57	815.26	2,956.97	63.67	91.92	6.91	47.28	8.21	70.28	1,010.62	261.06	429.06
641003 Transportation OH	113,803.93	109,441.48	71,351.01	3,789.90	4,853.80	17,604.84	379.08	547.25	41.16	281.52	48.87	418.39	6,016.91	1,554.28	2,554.46
641005 Stores Overhead -Qt	868.00	834.73	544.21	28.91	37.02	134.27	2.89	4.17	0.31	2.15	0.37	3.19	45.89	11.85	19.48
641013 SC NLOH fr Lab./Ser	669,264.23	643,609.32	419,604.82	22,287.87	28,544.51	103,531.46	2,229.34	3,218.33	242.04	1,655.56	287.42	2,460.52	35,384.56	9,140.52	15,022.38
642032 Transportation Allo	(8,034.00)	(7,726.03)	(5,037.03)	(267.55)	(342.65)	(1,242.82)	(26.76)	(38.63)	(2.91)	(19.87)	(3.45)	(29.54)	(424.76)	(109.72)	(180.33)
642087 Office Rent	(735,503.52)	(707,309.46)	(461,134.49)	(24,493.77)	(31,369.65)	(113,778.31)	(2,449.98)	(3,536.85)	(266.00)	(1,819.42)	(315.87)	(2,704.04)	(38,886.69)	(10,045.19)	(16,509.20)
642103 Allocated Depreciat	(16,119.90)	(15,501.98)	(10,106.60)	(536.83)	(687.52)	(2,493.66)	(53.70)	(77.52)	(5.83)	(39.88)	(6.92)	(59.26)	(852.27)	(220.16)	(361.83)
642608 BU Labor	4,787.18	4,603.67	3,001.39	159.42	204.18	740.55	15.95	23.02	1.73	11.84	2.06	17.60	253.10	65.38	107.45
642620 BU Non Labor Other	121,756.35	117,089.06	76,336.89	4,054.74	5,192.98	18,835.03	405.57	585.50	44.03	301.19	52.29	447.63	6,437.36	1,662.90	2,732.96
643001 Un labor-ST-IntAllo	1,322,812.07	1,272,104.71	829,356.02	44,052.35	56,418.71	204,631.68	4,406.33	6,361.07	478.40	3,272.24	568.10	4,863.26	69,938.18	18,066.39	29,691.99
643002 Un Labor 1 1/2-IntA	140,842.62	135,443.70	88,303.30	4,690.35	6,007.02	21,787.57	469.15	677.28	50.94	348.40	60.49	517.80	7,446.47	1,923.57	3,161.37
643003 Un Labor-DBL-Int Ac	27,723.81	26,661.07	17,381.84	923.26	1,182.44	4,288.72	92.35	133.32	10.03	68.58	11.91	101.93	1,465.78	378.64	622.29
643101 Labor-ST-NExmpt	1,920.57	1,846.95	1,204.13	63.96	81.91	297.10	6.40	9.24	0.69	4.75	0.82	7.06	101.54	26.23	43.11
643102 Labor 1 1/2-NExmpt	211.65	203.54	132.70	7.05	9.03	32.74	0.71	1.02	0.08	0.52	0.09	0.78	11.19	2.89	4.75
643502 Fleet Pool Vehicles	11,122.11	10,695.77	6,973.17	370.39	474.36	1,720.53	37.05	53.48	4.02	27.51	4.78	40.89	588.04	151.90	249.65
643508 IT Desktop Support	144,871.16	139,317.81	90,829.05	4,824.51	6,178.84	22,410.76	482.57	696.65	52.39	358.37	62.22	532.61	7,659.46	1,978.59	3,251.79
643536 Convenience Copiers	8,716.80	8,382.66	5,465.12	290.29	371.78	1,348.44	29.04	41.92	3.15	21.56	3.74	32.05	460.86	119.05	195.66
643538 IT Services	3,428.04	3,296.63	2,149.26	114.16	146.21	530.30	11.42	16.48	1.24	8.48	1.47	12.60	181.24	46.82	76.95
643563 Desktop Support Non	44,592.00	42,882.65	27,957.59	1,485.00	1,901.87	6,898.13	148.54	214.43	16.13	110.31	19.15	163.94	2,357.62	609.02	1,000.92
643567 Tele/VoIP Non Labor	309,493.80	297,629.97	194,041.58	10,306.78	13,200.09	47,876.97	1,030.93	1,488.28	111.93	765.60	132.92	1,137.84	16,363.20	4,226.93	6,946.93
643568 Mnfrm Data Strg Non	22,257.16	21,403.98	13,954.45	741.21	949.28	3,443.06	74.14	107.03	8.05	55.06	9.56	81.83	1,176.75	303.98	499.59
643569 Mnfrm CPU Util Non	56,893.75	54,712.84	35,670.35	1,894.68	2,426.55	8,801.15	189.51	273.59	20.58	140.74	24.43	209.17	3,008.02	777.03	1,277.04
646608 SC Labor	6,781,129.68	6,521,188.64	4,251,526.60	225,825.50	289,219.13	1,049,003.08	22,588.15	32,608.77	2,452.42	16,774.50	2,912.24	24,930.51	358,524.00	92,613.72	152,210.02
646614 SC Donation	703.29	676.33	440.94	23.42	30.00	108.80	2.34	3.38	0.25	1.74	0.30	2.59	37.18	9.61	15.79
646618 SC Misc. Bus Expen.	1,690.35	1,625.55	1,059.79	56.29	72.09	261.49	5.63	8.13	0.61	4.18	0.73	6.21	89.37	23.09	37.94
646619 SC Alloc. Ben. Othe	(1,261.48)	(1,213.12)	(790.90)	(42.01)	(53.80)	(195.14)	(4.20)	(6.07)	(0.46)	(3.12)	(0.54)	(4.64)	(66.70)	(17.23)	(28.32)
646620 SC Non Labor Other	6,975,310.96	6,707,926.36	4,373,271.34	232,292.13	297,501.07	1,079,041.84	23,234.97	33,542.54	2,522.64	17,254.85	2,995.63	25,644.41	368,790.53	95,265.77	156,568.64
722150 Property Tax	142,475.28	137,013.78	89,326.92	4,744.72	6,076.65	22,040.13	474.59	685.13	51.53	352.44	61.19	523.80	7,532.79	1,945.87	3,198.02
9030 Cust Records & Colle	**20,763,322.03**	**19,967,401.61**	**13,017,862.81**	**691,461.13**	**885,567.78**	**3,211,970.53**	**69,163.25**	**99,845.66**	**7,509.12**	**51,362.30**	**8,917.07**	**76,335.39**	**1,097,774.21**	**283,576.44**	**466,055.93**

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case Date of Request: 1/4/2022
Requested From: CenterPoint Energy Minnesota Gas Response Due: 1/14/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 7009	Subject: service lines A. Provide the total number of service lines in the Company's Minnesota service area that were in-service as of January 1, 2022. B. Are there any service lines in the Company's Minnesota service area that provide service to more than one customer class? If so, provide a list shared service lines with the number of customers served by customer class for each shared line. C. What is the largest number of meters served by a single service line in the Company's Minnesota service area? For this service line, list the number of meters served by customer class. **Response:** A. As of December 31, 2021, CenterPoint Energy's Property Accounting records show 807,049 plant in-service, service lines. B. Yes, see attached list of 1,395 shared service lines with 29,093 meters by customer class (OAG 7009_Attachment 1). This list was generated using limited SAP equipment records where the service line and meter equipment records are tied to one another. Many service line and meter equipment records are not tied to one another in SAP, especially in multiple meter situations. This connection in SAP, while necessary to pull this type of date request, is not necessary to run the business. C. An Edina apartment building with 185 meters, one commercial and 184 residential.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

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State of Minnesota
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Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case | Date of Request: 1/4/2022
Requested From: CenterPoint Energy Minnesota Gas | Response Due: 1/14/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Cost of Service

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 7010	Subject: Minimum System study and Zero Intercept study Reference: CPE responses to DOC IRs 701 (attachment 5) and 706 Why does the Company's Zero Intercept study include fewer observations (880) than the Company's Minimum System study (1,285)? If certain distribution mains were excluded from the Zero Intercept study, list the exclusion criteria and provide a narrative description of how these criteria were developed. **Response:** The same data set and number of observations (1,285) was analyzed for both the Minimum System study and the Zero Intercept study. For the Zero Intercept study the Company followed the same process to complete the regression analysis used in prior years as detailed in Docket No. G-008/GR-17-285, Exhibit ___(RAF-WP), Workpaper 16. In summary, as part of completing the regression analysis it was determined that a limited number of data points should be eliminated from the data set because they were either unrepresentative or erroneous.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case   Date of Request: 1/4/2022
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 1/14/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 7011	Subject: Zero Intercept study Reference: CPE response to DOC IR 706 Explain why the Company believes the results of the Zero Intercept study are "anomalous when compared to the Minimum System Approach." Include in your response whether the Company believes the results are anomalous for steel, plastic, or both. **Response:** The results are anomalous because the Zero Intercept Study (which uses a regression analysis to theoretically determine the cost per foot associated with a zero-inch diameter distribution main to determine the customer cost component) results in a higher customer-related percentage than the minimum system study (which uses the most commonly installed, minimum-sized pipe which in the case is two inches). If the Zero Intercept Study results were adopted, the customer-related percentage of mains would increase compared to the CCOSS currently sponsored by Mr. Zarumba. The results for steel versus plastic cannot be interpreted separately because the system is a combination of the two materials.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case — Date of Request: 1/20/2022
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 1/27/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Cost of Service

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	

OAG 7014	Subject: Class Cost of Service Study
	
	Reference: Zarumba Workpaper[1]
	
	Provide an updated version of the Company's embedded CCOSS—in live Excel spreadsheet with all formulae and links intact—with the following modifications:
	
	• Classify FERC accounts 374-378 (inclusive), 875, 877, 886-889 (inclusive), and 891 as commodity- and demand-related, using the forecasted test-year system load factor to classify the commodity-related portion and classifying the remainder as demand-related (i.e. using the Peak & Average methodology).
	
	• Allocate FERC accounts 380 and 892 as follows (and update account 874 to reflect these changes):
	  ◦ Residential: 76.55%
	  ◦ Commercial – A: 6.12%
	  ◦ Commercial/Industrial – B: 5.41%
	  ◦ Commercial/Industrial – C (S&T): 10.17%
	  ◦ Small Dual Fuel – A: 0.46%
	  ◦ Small Dual Fuel – B: 0.17%
	  ◦ Large Volume: 1.13%
	
	• Update all internal allocators—i.e. those that are derived based on the classification of other FERC accounts within the CCOSS, such as FERC accounts 386-397—to account for the changes above.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

[1]The due date for this IR is less than the standard 8 business days because of a discovery agreement reached between CenterPoint and the OAG to extend the due date for the company's response to OAG IR No. 7009.

Response:

Please see the attached spreadsheet CARD 2021_10_19 - WP 1, 5 and Schedules OAG 7014.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

CenterPoint Energy - Minnesota Gas

Docket No. G-008/GR-21-435 - Test Year Ending December 2022, Using the Minimum System Method

Overall Class Cost of Service Summary

Line	Column (A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				Firm Commercial/Industrial											
No.	Particulars	Total	Residential Sales Service	A - Sales Service	B - Sales Service	C - Sales Service	C - Transport	Sm Vol Dual Fuel - A - Sales Service	Sm Vol Dual Fuel - A - Transport	Sm Vol Dual Fuel - B - Sales Service	Sm Vol Dual Fuel - B - Transport	Large Firm - Sales Service	Large Firm - Transport	Lg Dual Fuel Sales Service	Lg Dual Fuel Transport
1	Operating & Maintenance Expense	$ 182,675,524	$ 100,114,851	$ 4,313,531	$ 7,447,059	$ 34,100,826	$ 1,392,727	$ 3,273,539	$ 259,972	$ 1,938,908	$ 323,895	$ 847,168	$ 11,860,338	$ 5,074,946	$ 11,727,763
2	Depreciation	115,417,249	63,106,055	3,292,471	4,773,314	19,314,871	994,434	1,746,648	148,916	1,013,541	173,265	576,224	9,239,880	3,394,888	7,642,741
3	Taxes Other Than Income	50,249,668	25,709,315	1,201,661	2,036,292	9,226,175	493,206	876,610	74,666	518,914	88,515	247,910	4,601,139	1,446,447	3,728,817
4	Subtotal	348,342,441	188,930,222	8,807,663	14,256,666	62,641,872	2,880,367	5,896,797	483,554	3,471,363	585,675	1,671,302	25,701,358	9,916,281	23,099,322
5	Income Taxes (incl. taxes on deficiency)	29,695,552	15,121,208	707,019	1,210,834	5,489,586	292,431	508,194	43,452	301,288	51,483	147,023	2,786,679	842,895	2,193,460
6	Return on Rate Base	123,700,909	62,989,476	2,945,184	5,043,896	22,867,625	1,218,163	2,116,951	181,006	1,255,056	214,460	612,444	11,608,296	3,511,195	9,137,158
7	Total Gross Cost of Service	501,738,902	267,040,906	12,459,866	20,511,396	90,999,083	4,390,962	8,521,942	708,012	5,027,707	851,618	2,430,769	40,096,332	14,270,371	34,429,939
8	Less: Revenue Credits to the Cost of Service (under current tarif	(5,270,695)	(2,720,859)	(126,937)	(208,456)	(928,514)	(87,239)	(153,124)	(17,859)	(64,213)	(11,374)	(27,646)	(407,683)	(157,443)	(359,348)
9	Total Net Cost of Service	496,468,207	264,320,047	12,332,929	20,302,940	90,070,569	4,303,722	8,368,818	690,153	4,963,494	840,244	2,403,122	39,688,650	14,112,928	34,070,591
10	Net Revenues under Current Base Rates (Incl CCRC & GAP)	429,402,444	276,459,878	11,068,128	17,608,221	75,718,036	2,154,705	6,194,281	542,645	3,582,620	651,983	1,546,068	15,123,975	6,986,293	11,765,612
11	risdictional Cost-of-Service Excess (Deficiency)-Current Tariff:	$ (67,065,763)	$ 12,139,832	$ (1,264,801)	$ (2,694,720)	$ (14,352,533)	$ (2,149,018)	$ (2,174,538)	$ (147,508)	$ (1,380,874)	$ (188,261)	$ (857,054)	$ (24,564,675)	$ (7,126,635)	$ (22,304,979)

CenterPoint Energy - Minnesota Gas
Docket No. G-008/GR-21-435 - Test Year Ending December 2022, Using the Minimum System Method
Cost of Service Model Results

Line No.	Column (A) Particulars	(B) Total	(C) Residential Sales Service	(D) Firm Commercial/Industrial A - Sales Service	(E) Firm Commercial/Industrial B - Sales Service	(F) Firm Commercial/Industrial C - Sales Service	(G) Firm Commercial/Industrial C - Tranpsort	(H) Sm Vol Dual Fuel - A - Sales Service	(I) Sm Vol Dual Fuel - A - Transport	(J) Sm Vol Dual Fuel - B - Sales Service	(K) Sm Vol Dual Fuel - B - Transport	(L) Large Firm - Sales Service	(M) Large Firm - Transport	(N) Lg Dual Fuel Sales Service	(O) Lg Dual Fuel Transport
1	Jurisdictional Cost-of-Service Excess (Deficiency)-Current Tariff:	$ (67,065,763)	$ 12,139,832	$ (1,264,801)	$ (2,694,720)	$ (14,352,533)	$ (2,149,018)	$ (2,174,538)	$ (147,508)	$ (1,380,874)	$ (188,261)	$ (857,054)	$ (24,564,675)	$ (7,126,635)	$ (22,304,979)
2															
3	Net Cost of Service:														
4	Customer	168,645,972	113,528,717	7,210,498	7,745,830	22,369,886	692,596	1,451,866	115,848	578,667	99,346	716,022	4,695,039	4,392,270	5,049,386
5	Capacity	289,172,812	132,000,174	4,539,530	10,965,242	58,383,930	3,404,528	5,888,721	497,001	3,702,541	622,454	1,408,830	33,989,132	7,965,775	25,804,953
6	Commodity	38,649,424	18,791,156	582,901	1,591,868	9,316,753	206,598	1,028,231	77,305	682,285	118,443	278,270	1,004,479	1,754,882	3,216,251
7	Total	496,468,207	264,320,047	12,332,929	20,302,940	90,070,569	4,303,722	8,368,818	690,153	4,963,494	840,244	2,403,122	39,688,650	14,112,928	34,070,591
8															
9	Recovery of Cost of Service:														
10															
11	Customer Costs (line 4)	168,645,972	113,528,717	7,210,498	7,745,830	22,369,886	692,596	1,451,866	115,848	578,667	99,346	716,022	4,695,039	4,392,270	5,049,386
12	Customer Numbers	905,925	833,823	28,475	20,527	21,295	423	851	64	144	25	22	46	137	93
13	Monthly Basic Charge [line 11/ (line 12 x 12 months)]	$ 15.51	$ 11.35	$ 21.10	$ 31.45	$ 87.54	$ 136.45	$ 142.17	$ 150.84	$ 334.88	$ 331.15	$ 2,712.21	$ 8,505.51	$ 2,671.70	$ 4,524.54
14															
15	Recovery of Capacity/Commodity thru Volumetric charge:														
16	Capacity Costs (line 5)	289,172,812	132,000,174	4,539,530	10,965,242	58,383,930	3,404,528	5,888,721	497,001	3,702,541	622,454	1,408,830	33,989,132	7,965,775	25,804,953
17	Commodity Cost (line 6)	38,649,424	18,791,156	582,901	1,591,868	9,316,753	206,598	1,028,231	77,305	682,285	118,443	278,270	1,004,479	1,754,882	3,216,251
18	Subtotal	327,822,235	150,791,329	5,122,431	12,557,110	67,700,683	3,611,126	6,916,953	574,306	4,384,826	740,897	1,687,100	34,993,611	9,720,658	29,021,205
19															
20	Annual Sales Volume (DT)	188,709,481	74,187,839	2,301,566	6,284,047	36,772,253	815,746	4,055,188	304,973	2,690,006	467,015	1,098,284	31,499,252	6,919,801	21,313,511
21															
22	Usage Charge (line 18 / line 20)	$1.73718	$2.03256	$2.22563	$1.99825	$1.84108	$4.42678	$1.70570	$1.88314	$1.63004	$1.58645	$1.53612	$1.11093	$1.40476	$1.36163

State of Minnesota
Minnesota Department of Commerce

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case — Date of Request: 1/20/2022
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 1/27/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Cost of Service

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	

OAG 7015	Subject: Class Cost of Service Study
	Reference: Zarumba Workpaper[1]
	Provide an updated version of the Company's embedded CCOSS—in live Excel spreadsheet with all formulae and links intact—with the following modifications:
	• Classify FERC accounts 374-378 (inclusive), 875, 877, 886-889 (inclusive), and 891 as 100% demand-related (i.e. using the Basic Customer methodology).
	• Allocate FERC accounts 380 and 892 as follows (and update account 874 to reflect these changes):
	  ◦ Residential: 76.55%
	  ◦ Commercial – A: 6.12%
	  ◦ Commercial/Industrial – B: 5.41%
	  ◦ Commercial/Industrial – C (S&T): 10.17%
	  ◦ Small Dual Fuel – A: 0.46%
	  ◦ Small Dual Fuel – B: 0.17%
	  ◦ Large Volume: 1.13%
	• Update all internal allocators—i.e. those that are derived based on the classification of other FERC accounts within the CCOSS, such as FERC accounts 386-397—to account for the changes above.
	______________________
	[2]The due date for this IR is less than the standard 8 business days because of a discovery agreement reached between CenterPoint and the OAG to extend the due date for the company's response to OAG IR No. 7009.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

Response:

Please see the attached spreadsheet - CARD 2021_10_19 - WP 1, 5 and Schedules OAG 7015.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

CenterPoint Energy - Minnesota Gas
Docket No. G-008/GR-21-435 - Test Year Ending December 2022, Using the Minimum System Method
Overall Class Cost of Service Summary

Line	Column (A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				Firm Commercial/Industrial											
No.	Particulars	Total	Residential Sales Service	A - Sales Service	B - Sales Service	C - Sales Service	C - Transport	Sm Vol Dual Fuel - A - Sales Service	Sm Vol Dual Fuel - A - Transport	Sm Vol Dual Fuel - B - Sales Service	Sm Vol Dual Fuel - B - Transport	Large Firm - Sales Service	Large Firm - Transport	Lg Dual Fuel Sales Service	Lg Dual Fuel Transport
1	Operating & Maintenance Expense	$ 182,675,524	$ 107,203,278	$ 4,720,805	$ 8,475,261	$ 36,450,260	$ 781,666	$ 2,054,166	$ 148,207	$ 1,194,084	$ 197,668	$ 840,328	$ 9,986,325	$ 3,756,325	$ 6,867,151
2	Depreciation	115,417,249	69,308,334	3,648,830	5,672,977	21,370,595	459,763	679,713	51,123	361,830	62,818	570,240	7,600,144	2,241,113	3,389,769
3	Taxes Other Than Income	50,249,668	28,845,568	1,381,859	2,491,217	10,265,675	222,844	337,103	25,215	189,368	32,666	244,884	3,771,988	863,028	1,578,254
4	Subtotal	348,342,441	205,357,180	9,751,494	16,639,455	68,086,530	1,464,272	3,070,982	224,545	1,745,282	293,152	1,655,452	21,358,457	6,860,466	11,835,174
5	Income Taxes (incl. taxes on deficiency)	29,695,552	16,974,313	813,491	1,479,634	6,103,791	132,683	189,417	14,234	106,571	18,484	145,235	2,296,762	498,172	922,765
6	Return on Rate Base	123,700,909	70,708,839	3,388,710	6,163,618	25,426,181	552,711	789,043	59,293	443,935	76,997	604,995	9,567,478	2,075,205	3,843,904
7	Total Gross Cost of Service	501,738,902	293,040,333	13,953,695	24,282,706	99,616,503	2,149,666	4,049,442	298,072	2,295,788	388,633	2,405,681	33,222,697	9,433,843	16,601,843
8	Less: Revenue Credits to the Cost of Service (under current tarif	(5,270,695)	(2,981,652)	(141,921)	(246,285)	(1,014,952)	(64,758)	(108,261)	(13,747)	(36,810)	(6,730)	(27,395)	(338,735)	(108,930)	(180,520)
9	Total Net Cost of Service	496,468,207	290,058,681	13,811,774	24,036,422	98,601,550	2,084,908	3,941,181	284,325	2,258,978	381,903	2,378,286	32,883,962	9,324,913	16,421,323
10	Net Revenues under Current Base Rates (Incl CCRC & GAP)	429,402,444	276,459,878	11,068,128	17,608,221	75,718,036	2,154,705	6,194,281	542,645	3,582,620	651,983	1,546,068	15,123,975	6,986,293	11,765,612
11	risdictional Cost-of-Service Excess (Deficiency)-Current Tariff:	$ (67,065,763)	$ (13,598,803)	$ (2,743,645)	$ (6,428,201)	$ (22,883,514)	$ 69,796	$ 2,253,100	$ 258,320	$ 1,323,641	$ 270,080	$ (832,219)	$ (17,759,987)	$ (2,338,620)	$ (4,655,711)

CenterPoint Energy - Minnesota Gas
Docket No. G-008/GR-21-435 - Test Year Ending December 2022, Using the Minimum System Method
Cost of Service Model Results

Line	Column (A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				Firm Commercial/Industrial											
No.	Particulars	Total	Residential Sales Service	A - Sales Service	B - Sales Service	C - Sales Service	C - Tranpsort	Sm Vol Dual Fuel - A - Sales Service	Sm Vol Dual Fuel - A - Transport	Sm Vol Dual Fuel - B - Sales Service	Sm Vol Dual Fuel - B - Transport	Large Firm - Sales Service	Large Firm - Transport	Lg Dual Fuel Sales Service	Lg Dual Fuel Transport
1	Jurisdictional Cost-of-Service Excess (Deficiency)-Current Tariff:	$ (67,065,763)	$ (13,598,803)	$ (2,743,645)	$ (6,428,201)	$ (22,883,514)	$ 69,796	$ 2,253,100	$ 258,320	$ 1,323,641	$ 270,080	$ (832,219)	$ (17,759,987)	$ (2,338,620)	$ (4,655,711)
2															
3	Net Cost of Service:														
4	Customer	168,113,072	115,484,695	7,283,985	8,058,410	23,172,543	475,629	1,019,822	75,347	315,221	54,680	713,942	4,033,762	4,052,124	3,372,913
5	Capacity	289,701,831	155,783,015	5,944,890	14,386,195	66,112,519	1,402,687	1,892,668	131,663	1,260,920	208,688	1,386,074	27,845,687	3,517,091	9,829,734
6	Commodity	38,653,304	18,790,971	582,899	1,591,817	9,316,489	206,592	1,028,691	77,315	682,837	118,535	278,271	1,004,512	1,755,699	3,218,677
7	Total	496,468,207	290,058,681	13,811,774	24,036,422	98,601,550	2,084,908	3,941,181	284,325	2,258,978	381,903	2,378,286	32,883,962	9,324,913	16,421,323
8															
9	Recovery of Cost of Service:														
10															
11	Customer Costs (line 4)	168,113,072	115,484,695	7,283,985	8,058,410	23,172,543	475,629	1,019,822	75,347	315,221	54,680	713,942	4,033,762	4,052,124	3,372,913
12	Customer Numbers	905,925	833,823	28,475	20,527	21,295	423	851	64	144	25	22	46	137	93
13	Monthly Basic Charge [line 11/ (line 12 x 12 months)]	$ 15.46	$ 11.54	$ 21.32	$ 32.71	$ 90.68	$ 93.70	$ 99.87	$ 98.11	$ 182.42	$ 182.27	$ 2,704.32	$ 7,307.54	$ 2,464.80	$ 3,022.32
14															
15	Recovery of Capacity/Commodity thru Volumetric charge:														
16	Capacity Costs (line 5)	289,701,831	155,783,015	5,944,890	14,386,195	66,112,519	1,402,687	1,892,668	131,663	1,260,920	208,688	1,386,074	27,845,687	3,517,091	9,829,734
17	Commodity Cost (line 6)	38,653,304	18,790,971	582,899	1,591,817	9,316,489	206,592	1,028,691	77,315	682,837	118,535	278,271	1,004,512	1,755,699	3,218,677
18	Subtotal	328,355,135	174,573,986	6,527,789	15,978,012	75,429,008	1,609,279	2,921,359	208,978	1,943,757	327,223	1,664,345	28,850,199	5,272,790	13,048,411
19															
20	Annual Sales Volume (DT)	188,709,481	74,187,839	2,301,566	6,284,047	36,772,253	815,746	4,055,188	304,973	2,690,006	467,015	1,098,284	31,499,252	6,919,801	21,313,511
21															
22	Usage Charge (line 18 / line 20)	$1.74000	$2.35313	$2.83624	$2.54263	$2.05125	$1.97277	$0.72040	$0.68523	$0.72258	$0.70067	$1.51541	$0.91590	$0.76199	$0.61221

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case — Date of Request: 1/20/2022
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 1/27/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Cost of Service

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 7016	Subject: Class Cost of Service Study Reference: Zarumba Workpaper 1 Provide an updated version of the Company's embedded CCOSS—in live Excel spreadsheet with all formulae and links intact—with the following modifications: • Classify FERC accounts 374-376 (inclusive), 877, 886, 887, and 891 as 14.4% customer-related and 85.6% demand-related. Allocate the customer-related portion of these accounts using the following customer premise counts: ◦ Residential: 741,511 ◦ Com/Ind A: 21,914 ◦ Com/Ind B: 18,551 ◦ Com/Ind C: 19,100 ◦ Large Dual Fuel: 230 ◦ Large Firm: 66 ◦ Small Dual Fuel A: 879 ◦ Small Dual Fuel B: 181 • Classify FERC accounts 378, 875, 889 as 100% demand-related. • Allocate FERC accounts 380 and 892 as follows (and update account 874 to reflect these changes): ◦ Residential: 76.55% ◦ Commercial – A: 6.12% ◦ Commercial/Industrial – B: 5.41% ◦ Commercial/Industrial – C (S&T): 10.17%

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

- Small Dual Fuel – A: 0.46%
- Small Dual Fuel – B: 0.17%
- Large Volume: 1.13%

- Update all internal allocators—i.e. those that are derived based on the classification of other FERC accounts within the CCOSS, such as FERC accounts 386-397—to account for the changes above.

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[3]The due date for this IR is less than the standard 8 business days because of a discovery agreement reached between CenterPoint and the OAG to extend the due date for the company's response to OAG IR No. 7009.

Response:

Please see the attached spreadsheet file CARD 2021_10_19 WP 1, 5 and Schedules OAG 7016.

Response By: Ralph Zarumba
Title: Managing Director
Department: Black & Veatch Management Consulting, LLC
Telephone: Drew Sudbury: 612-321-4480

CenterPoint Energy - Minnesota Gas

OAG 7016 -Docket No. G-008/GR-21-435 - Test Year Ending December 2022, Using the Minimum System Method

Overall Class Cost of Service Summary

Line	Column (A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				Firm Commercial/Industrial											
No.	Particulars	Total	Residential Sales Service	A - Sales Service	B - Sales Service	C - Sales Service	C - Transport	Sm Vol Dual Fuel - A - Sales Service	Sm Vol Dual Fuel - A - Transport	Sm Vol Dual Fuel - B - Sales Service	Sm Vol Dual Fuel - B - Transport	Large Firm - Sales Service	Large Firm - Transport	Lg Dual Fuel Sales Service	Lg Dual Fuel Transport
1	Operating & Maintenance Expense	$ 182,675,524	$ 110,816,995	$ 5,389,227	$ 8,228,814	$ 34,364,502	$ 734,519	$ 1,976,287	$ 142,350	$ 1,140,144	$ 188,303	$ 779,843	$ 8,872,344	$ 3,581,599	$ 6,460,596
2	Depreciation	115,417,249	72,190,303	4,504,145	5,476,027	19,624,252	420,014	602,311	45,302	309,829	53,790	512,591	6,605,283	2,060,904	3,012,498
3	Taxes Other Than Income	50,249,668	30,517,598	1,632,854	2,377,262	9,315,614	201,418	303,834	22,713	166,036	28,615	218,600	3,275,812	789,574	1,399,737
4	Subtotal	348,342,441	213,524,895	11,526,226	16,082,103	63,304,367	1,355,952	2,882,432	210,365	1,616,009	270,708	1,511,035	18,753,439	6,432,077	10,872,831
5	Income Taxes (incl. taxes on deficiency)	29,695,552	17,964,188	960,492	1,412,172	5,541,746	120,010	169,797	12,758	92,802	16,093	129,721	2,003,542	454,888	817,342
6	Return on Rate Base	123,700,909	74,832,298	4,001,063	5,882,598	23,084,906	499,917	707,314	53,146	386,579	67,040	540,370	8,346,030	1,894,899	3,404,751
7	Total Gross Cost of Service	501,738,902	306,321,382	16,487,781	23,376,873	91,931,019	1,975,878	3,759,543	276,270	2,095,390	353,842	2,181,126	29,103,010	8,781,864	15,094,924
8	Less: Revenue Credits to the Cost of Service (under current tarif	(5,270,695)	(3,114,403)	(167,703)	(237,230)	(938,016)	(63,018)	(105,342)	(13,527)	(34,794)	(6,380)	(25,137)	(297,407)	(102,356)	(165,383)
9	Total Net Cost of Service	496,468,207	303,206,979	16,320,078	23,139,644	90,993,004	1,912,861	3,654,201	262,742	2,060,596	347,461	2,155,989	28,805,603	8,679,508	14,929,541
10	Net Revenues under Current Base Rates (Incl CCRC & GAP)	429,402,444	276,459,878	11,068,128	17,608,221	75,718,036	2,154,705	6,194,281	542,645	3,582,620	651,983	1,546,068	15,123,975	6,986,293	11,765,612
11	risdictional Cost-of-Service Excess (Deficiency)-Current Tariff:	$ (67,065,763)	$ (26,747,101)	$ (5,251,950)	$ (5,531,423)	$ (15,274,968)	$ 241,844	$ 2,540,080	$ 279,903	$ 1,522,024	$ 304,521	$ (609,921)	$ (13,681,628)	$ (1,693,215)	$ (3,163,929)

CenterPoint Energy - Minnesota Gas
OAG 7016 -Docket No. G-008/GR-21-435 - Test Year Ending December 2022, Using the Minimum System Method
Cost of Service Model Results

Line	Column (A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				Firm Commercial/Industrial											
No.	Particulars	Total	Residential Sales Service	A - Sales Service	B - Sales Service	C - Sales Service	C - Tranpsort	Sm Vol Dual Fuel - A - Sales Service	Sm Vol Dual Fuel - A - Transport	Sm Vol Dual Fuel - B - Sales Service	Sm Vol Dual Fuel - B - Transport	Large Firm - Sales Service	Large Firm - Transport	Lg Dual Fuel Sales Service	Lg Dual Fuel Transport
1	Jurisdictional Cost-of-Service Excess (Deficiency)-Current Tariff:	$ (67,065,763)	$ (26,747,101)	$ (5,251,950)	$ (5,531,423)	$ (15,274,968)	$ 241,844	$ 2,540,080	$ 279,903	$ 1,522,024	$ 304,521	$ (609,921)	$ (13,681,628)	$ (1,693,215)	$ (3,163,929)
2															
3	Net Cost of Service:														
4	Customer	206,276,339	149,741,779	10,506,599	9,003,897	23,966,202	487,708	972,724	71,684	275,622	47,805	667,779	3,579,209	3,832,135	3,123,195
5	Capacity	251,537,704	134,674,430	5,230,605	12,543,909	57,709,970	1,218,562	1,652,764	113,747	1,102,078	181,111	1,209,924	24,221,829	3,091,505	8,587,269
6	Commodity	38,654,165	18,790,770	582,875	1,591,837	9,316,831	206,591	1,028,713	77,312	682,896	118,545	278,285	1,004,565	1,755,869	3,219,076
7	Total	496,468,207	303,206,979	16,320,078	23,139,644	90,993,004	1,912,861	3,654,201	262,742	2,060,596	347,461	2,155,989	28,805,603	8,679,508	14,929,541
8															
9	Recovery of Cost of Service:														
10															
11	Customer Costs (line 4)	206,276,339	149,741,779	10,506,599	9,003,897	23,966,202	487,708	972,724	71,684	275,622	47,805	667,779	3,579,209	3,832,135	3,123,195
12	Customer Numbers	905,925	833,823	28,475	20,527	21,295	423	851	64	144	25	22	46	137	93
13	Monthly Basic Charge [line 11/ (line 12 x 12 months)]	$ 18.97	$ 14.97	$ 30.75	$ 36.55	$ 93.79	$ 96.08	$ 95.25	$ 93.34	$ 159.50	$ 159.35	$ 2,529.47	$ 6,484.07	$ 2,330.98	$ 2,798.56
14															
15	Recovery of Capacity/Commodity thru Volumetric charge:														
16	Capacity Costs (line 5)	251,537,704	134,674,430	5,230,605	12,543,909	57,709,970	1,218,562	1,652,764	113,747	1,102,078	181,111	1,209,924	24,221,829	3,091,505	8,587,269
17	Commodity Cost (line 6)	38,654,165	18,790,770	582,875	1,591,837	9,316,831	206,591	1,028,713	77,312	682,896	118,545	278,285	1,004,565	1,755,869	3,219,076
18	Subtotal	290,191,868	153,465,200	5,813,480	14,135,747	67,026,801	1,425,153	2,681,477	191,058	1,784,974	299,656	1,488,209	25,226,394	4,847,373	11,806,346
19															
20	Annual Sales Volume (DT)	188,709,481	74,187,839	2,301,566	6,284,047	36,772,253	815,746	4,055,188	304,973	2,690,006	467,015	1,098,284	31,499,252	6,919,801	21,313,511
21															
22	Usage Charge (line 18 / line 20)	$1.53777	$2.06860	$2.52588	$2.24947	$1.82275	$1.74706	$0.66125	$0.62648	$0.66356	$0.64164	$1.35503	$0.80086	$0.70051	$0.55394

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case   Date of Request: 12/16/2021
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 12/29/2021

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Other

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 9002	Subject: Transmission line replacement costs Complete the following table detailing each transmission pipeline replacement project in the Company's Minnesota service area from 2016 through 2020 (inclusive). [See attached OAG 9002 RFI Table...it could not be copied/created in this RFI] **Response:** Please see the attachment. The Company did not use the Handy-Whitman index in creating the Integrity Management test year forecast and thus did not include the "HW Index" or adjusted project cost columns in the table.

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480

OAG No. 9002

State of Minnesota
Office of the Attorney General
Utility Information Request

In the Matter of CenterPoint Energy's 2021 General Rate Case	**MPUC Docket No.**	G-008/GR-21-435

Requested from: CenterPoint Energy

Requested By: Andrew Twite	**Date of Request:**	December 16, 2021
	Due Date:	December 29, 2021

Subject: Transmission line replacement costs

Complete the following table detailing each transmission pipeline replacement project in the Company's Minnesota service area from 2016 through 2020 (inclusive).

			Line that was replaced			New Line					
Year	Project ID#	Location	Length	Material	Diameter	Length	Material	Diameter	Project Cost (nominal)	HW Index	Project cost ($2020)

Response by_____________________________
Title__________________________________
Department______________________________
Telephone_______________________________
Email _________________________________

CenterPoint Energy Minnesota Gas
Docket No. G-008/GR-21-435
Response to OAG IR #9002

This is the table that the Company was asked to complete:

			Line that was replaced			New Line					
Year	Project ID#	Location	Length	Material	Diameter	Length	Material	Diameter	Project Cost (nominal)	HW Index	Project cost ($2020)

Proj Year	Order	Functional Location	Retired Footage	Retired Type	Retired Size	Inst Footage	Inst Type	Inst Size	Actual Cost (No COH)
2016	71635923	BROOKLYN CTR	16,694	STEEL	24	16,617	STEEL	24	$19,986,018
2016	71636087	EDINA	9,095	STEEL	24	10,418	STEEL	24	$7,992,468
2016	71636315	EDINA	8,978	STEEL	24	9,168	STEEL	24	$6,936,266
2016	74171912	EDINA	1,660	STEEL	24	1,681	STEEL	24	$2,440,069
2017	78231593	FRIDLEY	3,328	STEEL	20	3,405	STEEL	20	$2,643,786
2017	80574043	BROOKLYN PARK	16,058	STEEL	24	16,087	STEEL	24	$12,640,516
2017	82953995	HOPKINS	11,289	STEEL	24	11,349	STEEL	24	$16,638,228
2017	82954544	GOLDEN VALLEY	1,259	STEEL	24	1,067	STEEL	24	$1,997,043
2018	82197944	BLOOMINGTON	7,936	STEEL	20	7,232	STEEL	24	$6,000,446
2018	84879073	MINNEAPOLIS	2,023	STEEL	24	2,023	STEEL	24	$2,728,860
2018	84879080	GOLDEN VALLEY	1,333	STEEL	24	1,778	STEEL	24	$3,008,278
2018	85416653	RICHFIELD	6,637	STEEL	20	8,268	STEEL	24	$8,083,551
2018	86129072	MINNEAPOLIS	3,209	STEEL	24	3,245	STEEL	24	$4,345,709
2018	86868077	MINNEAPOLIS	1,002	STEEL	24	1,039	STEEL	24	$1,165,280
2019	80580763	GOLDEN VALLEY	2,881	STEEL	24	3,924	STEEL	24	$6,148,257
2019	83816665	MINNEAPOLIS	14,064	STEEL	20	14,147	STEEL	20	$12,768,503
2019	83816905	RICHFIELD	1,170	STEEL	24	1,196	STEEL	24	$1,495,848
2019	83817889	MINNEAPOLIS	2,812	STEEL	24	2,853	STEEL	24	$5,235,283
2019	88908051	ST LOUIS PARK	210	STEEL	24	1,115	STEEL	24	$1,740,979
2019	89470624	GOLDEN VALLEY	483	STEEL	24	476	STEEL	24	$442,813
2020	86129256	EDINA	1,935	STEEL	24	2,046	STEEL	24	$2,354,881
2020	88519248	GOLDEN VALLEY	6,534	STEEL	24	6,624	STEEL	24	$10,071,722
2020	90350688	EDINA	5,600	STEEL	24	5,145	STEEL	24	$5,787,173
2020	90350865	CRYSTAL	3,175	STEEL	24	3,202	STEEL	24	$3,348,592
2020	90350999	NEW HOPE	7,635	STEEL	24	5,957	STEEL	24	$7,016,361
2020	94722706	ST LOUIS PARK	9,891	STEEL	24	9,686	STEEL	24	$11,816,539
2016	80093883	COON RAPIDS	41	STEEL	24	41	STEEL	24	$95,678
2016	77349352	HASTINGS	9,136	STEEL	6	9,407	STEEL	8	$1,875,745
2016	77583294	EAGAN	93	STEEL	16	91	STEEL	16	$359,155
2016	77663680	BURNSVILLE	51	STEEL	16	51	STEEL	16	$263,530
2017	77320710	LAKEVILLE	1,086	STEEL	16	1,098	STEEL	16	$819,265
2017	80507383	BURNSVILLE	917	STEEL	20	817	STEEL	24	$1,077,626
2017	80573695	BLOOMINGTON	6,369	STEEL	16	7,095	STEEL	20	$4,902,019
2017	79826257	CHASKA	2,386	STEEL	8, 12	2,312	STEEL	8	$617,829
2017	81086003	SHAKOPEE	145	STEEL	6	145	STEEL	6	$104,612
2017	79988289	CHASKA	101	STEEL	12	104	STEEL	12	$503,959
2017	80257838	EXCELSIOR	642	STEEL	8	624	STEEL	12	$389,454
2017	82302141	SHOREWOOD	382	STEEL	8	705	STEEL	12,8	$639,344
2017	80574318	RICHFIELD	2,611	STEEL	20	2,596	STEEL	24	$2,383,848
2018	80580957	BLOOMINGTON	3,358	STEEL	16	5,758	STEEL	20, 24	$4,526,582
2018	83531616	BLOOMINGTON	9,391	STEEL	20	6,892	STEEL	24	$3,744,941
2018	83817409	MINNEAPOLIS	9,842	STEEL	20, 12	10,587	STEEL	20	$8,360,978

2018	85467671	COON RAPIDS	10	STEEL	20	10	STEEL	20	$85,199
2018	86668646	CHANHASSEN	123	STEEL	8	123	STEEL	8	$122,221
2018	88045018	MINNETONKA	52	STEEL	12	52	STEEL	12	$336,531
2018	86345073	WOODBURY	1,201	STEEL	2, 6	513	STEEL	8	$331,832
2018	86171696	COON RAPIDS	43	STEEL	24	43	STEEL	24	$126,329
2018	87763115	FRIDLEY	42	STEEL	24	42	STEEL	24	$498,264
2019	83817409	MINNEAPOLIS	9,842	STEEL	20	10,587	STEEL	20	$8,360,978
2019	88382247	COON RAPIDS	1,046	STEEL	24	1,034	STEEL	24	$1,608,596
2019	84377826	MARSHAN TWP	35,379	STEEL	6, 4	17,562	STEEL	8	$2,475,203
2019	90198960	DAHLGREN TWP	50	STEEL	12	50	STEEL	12	$227,159
2019	89644864	FRIDLEY	39	STEEL	24	39	STEEL	24	$235,767
2020	90787941	BURNSVILLE	10,956	STEEL	16, 24, 20	10,259	STEEL	24, 16	$11,149,459
2020	91983595	FRIDLEY	1,121	STEEL	24	1,145	STEEL	24	$890,926

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case | Date of Request: 1/6/2022
Requested From: CenterPoint Energy Minnesota Gas | Response Due: 1/19/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Engineering

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 9012	Subject: Bare Steel Main Replacement Project Reference: CPE response to OAG IR 9005, Attachment 1, part C Provide an updated version of the table included as Part C to Attachment 1 of CPE's response to OAG IR 9005 including both estimated and actual project costs. **Response:** Please see Attachment 1.

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480

CenterPoint Energy Minnesota Gas
Docket No. G-008/GR-21-435
Response to OAG IR #9012

The table below contains the same list of main projects that appeared in the Company's response to OAG IR #9005, which was itself an expanded version of the project list that appeared in Exhibit __ (JMW-WP) Sch. 2, Workpaper 5, pages 4 and 5. It is not a complete list of the Bare Steel Main Replacement projects the Company actually worked on during 2021. The Company adds and subtracts projects throughout the construction season for the reasons noted in the Company's response to OAG IR# 9013, and some projects were expanded in scope when budget became available due to the postponement of large-diameter projects.

Costs include postings through December 31, 2021; costs are still being received on many work orders. Differences between estimated and actual costs occur because of projects being more or less complicated than anticipated, changes in project scope, and in particular with regard to service lines, the fact that the number of service lines attached to each main is estimated at an early point in the design process based on the engineer's general sense of the density of the area and without any information about the mix between residential and commercial customers nor the number that will be replaced versus tested and reconnected.

Actual service line costs listed include associated meter work.

	(A) Project	(B)	(C)	(D) Main Estimate	(E) Service Lines Estimate	(F) Main Length (ft.)	(G) Main Material	(H) Main Diameter (in.)	(I) Actual Main Cost	(J) Actual Services Cost
1	80371188	RM BROADWAY AVE N AREA	WAYZATA	$206,502	$14,036	9,500	Plastic	2	$365,337	$363,031
2	86303090	RM 4" ST CL-6 & 2-1/2" CL-2 RR CROSSING.	WASECA	237,432	39,301	1,560	Plastic	4	2,445	0
3	86304159	RM DIVISION ST REPLACEMENT	ST LOUIS PARK	178,087	19,650	1,974	Plastic	3	86,831	0
4	86353649	RM DUGGAN PLAZA AREA REPLACEMENT	EDINA	770,731	283,527	20,000	Plastic	4	445,519	336,208
5	86767378	RM. Bare steel job. Replace portion of b	GOLDEN VALLEY	56,688	117,902	731	Plastic	3	102,881	13,190
6	88113523	RM WOODLAWN BARE STEEL	MINNEAPOLIS	3,678,889	14,036	8,149	Steel	16	3,779,827	40,708
7	88567720	RM ALLEY NORTH OF MAIN FROM GROVE ST N T	BELLE PLAINE	262,765	224,576	1,466	Plastic	4	3	0
8	89170140	RM 2nd ST SW	NEW PRAGUE	152,109	140,360	1,920	Steel	6	466,112	334
9	91431164	RM - REPLACING 2300' OF 3" STL CL-2 WITH	BLOOMINGTON	82,789	5,614	2,172	Plastic	6	68,440	39,723
10	91743899	RM - 1000' OF 3" CL-2 BARE STEEL REPLACE	ST LOUIS PARK	37,118	70,180	991	Plastic	2	42,887	66,988
11	92284117	RM REPLACE EXISTING 2" AND 1-1/2" ST ON	WASECA	140,000	126,324	370	Plastic	2	65,849	13,957
12	92540832	-HP RM RIVERSIDE PLAZA AREA, 6 ST S THRO	MINNEAPOLIS	357,915	182,468	300	Steel	20	389,698	0
13	92696675	REPLACING 3882' OF 3" BARE STEEL CL-2 WI	ST LOUIS PARK	245,673	171,239	3,882	Plastic	2	148,134	313,999
14	93736759	RM PHASE (2) 2 ST SE & 6 AVE SE - CUT IN	MINNEAPOLIS	199,732	0	100	Steel	20	0	0
15	94301485	RM SBAR job in St Louis Park. Replacing	ST LOUIS PARK	141,903	87,023	1,865	Plastic	2	65,720	193,478
16	94487552	HIGH PRIORITY SBAR JOB IN NORTHWEST MINN	MINNEAPOLIS	26,596	8,422	10	Plastic	3	6,241	5,685
17	94489028	HIGH PRIORITY SBAR JOB IN JORDAN. REPLAC	JORDAN	92,422	0	600	Plastic	2	1,726	0
18	94491283	RM - REPLACE APPROX. 1700' EXISTING 6" A	EDINA	110,092	14,036	1,800	Plastic	4	134,648	45,928
19	94830848	SBAR JOB LOCATED AT 9TH ST NE AND 4TH AV	WASECA	60,920	0	500	Plastic	2	24,287	10,367
20	95844387	RM - REPLACE APPROX. 875' OF 3" BARE STE	MINNETONKA	64,235	140,360	875	Plastic	2	27,223	11,600
21	96076756	RM - 17 AVE S PHASE I: REPLACE IN KIND A	MINNEAPOLIS	3,846,289	16,843	5,100	Steel	3	3,538,579	4,756
22	96126792	BARE STEEL REPLACEMENT PROJECT ALONG UPT	MINNEAPOLIS	4,611,236	67,373	4,440	Steel	24	104,819	0
23	96190513	RM - REPLACE 600' OF 3" BARE STEEL WITH	BLOOMINGTON	86,351	252,648	582	Plastic	2	39,995	29,188
24	96216772	RM HIGH PRIORITY BARE STEEL PROJECT 4500	EDINA	316,955	84,216	4,500	Plastic	4	187,603	130,874
25	96413100	RM - REPLACE APPROX 1200' OF 3" ST CL-2	HOPKINS	108,507	14,036	1,256	Plastic	4	116,637	27,695
26	96492559	RM - REPLACING APPROX 2300' OF 3", 2" BA	DEEPHAVEN	158,533	182,468	577 1,840	Plastic	2 4	136,546	15,735
27	96695118	Replacing existing 3" bare steel with 2"	MINNETONKA	279,119	2,807	7,370	Plastic	2	353,897	386,179
28	96815076	RM - REPLACING APPROX 5500' OF 4", 3", 2	BLOOMINGTON	369,714	0	5,688	Plastic	4	168,724	216,766
29	96895984	RM - Replace existing 4" bare steel with	EDINA	121,740	70,180	1,870	Plastic	3	71,897	83,915
30	96991965	RM WESTBROOK LN	EDINA	120,676	148,782	2,724	Plastic	2	78,528	0
31	97022114	RM - SYSTEM IMPROVEMENT: REPLACE 4" BARE	SAINT PETER	104,002	2,807	600	Plastic	2	54,573	15,628
32	97046191	RM - SYSTEM IMPROVEMENT: REPLACE BARE ST	BELLE PLAINE	255,569	0	6,700	Plastic	2	152,558	256,811
33	97071383	RM - SYSTEM IMPROVEMENT: REPLACE BARE ST	BLOOMINGTON	128,524	168,432	2,050	Plastic	2	65,338	102,009
34	97071605	RM - SYSTEM IMPROVEMENT: REPLACE 2" BARE	LAKE CRYSTAL	301,802	210,540	5,540	Plastic	2	156,586	233,975
35	97071747	RM - SYSTEM IMPROVEMENT: REPLACE 4" ST C	MINNEAPOLIS	101,582	266,684	1,290	Plastic	4	5,228	0
36	97071818	RM - SYSTEM IMPROVEMENT: REPLACE 3" ST C	SAINT PETER	152,174	280,720	2,600	Plastic	4	157,721	13,051
37	97071824	RM - SYSTEM IMPROVEMENT: REPLACE 2" ST C	BELLE PLAINE	333,703	33,686	2,900	Plastic	2	91,526	110,583
38	97072131	RM - SYSTEM IMPROVEMEN: REPLACE 3" ST CL	ST LOUIS PARK	164,877	112,288	3,970	Plastic	2	167,283	0
39	97100674	Replace existing 3" bare steel with 3" P	ST LOUIS PARK	255,510	303,178	1,726 2,814	Plastic	2 4	311,261	411,846
40	97102050	RM - REPLACE EXISTING 2950' OF 2" BARE S	CHASKA	158,137	280,720	4,705	Plastic	2	220,355	169,440
41	97102061	RM - REPLACING EXISTING 630' 4" BARE STE	HASTINGS	58,500	30,879	2,950	Plastic	4	13,643	0
42	97102852	RM - REPLACING APPROX 2400' 4" CL-2 BARE	MINNEAPOLIS	216,832	224,576	1,754 1,714	Plastic	2 4	*Order cancelled; became a Public Improvement project*	
43	97102939	RM - REPLACING APPROX 1500' 1 1/4" CL-2	WASECA	64,566	213,347	1,497	Plastic	2	77,256	15,383
44	97103104	RM - REPLACE APPROX 2400' OF 4" CL-2 BAR	MANKATO	141,792	550,211	1,953	Plastic	4	520,078	86,942
45	97103216	RM - REPLACE APPROX 7000' OF 3" AND 2" C	MERIDEN TWP	376,013	61,758	7,287	Plastic	3	197,483	74,576
46	97111822	RM - REPLACE APRROX 400' OF 2" CL-2 BARE	MANKATO	35,554	39,301	370	Plastic	2	29,624	3,167
47	97111824	RM - REPLACE APRROX 600' OF 2" CL-2 BARE	MANKATO	38,293	16,843	601	Plastic	2	78,741	12,588
48	97111827	RM - REPLACE APPROX 6000' OF 2" & 3" CL-	JANESVILLE	298,435	134,746	2,736 1,244 3,503	Plastic	2 3 4	310,101	138,355
49	97112189	RM - REPLACE APPROX 2000' OF 2", 3" & 4"	MANKATO	99,185	28,072	419 1,049 510	Plastic	2 4 6	22,689	454
50	97546957	RM - REPLACE ~1200' 3" ST CL-2 7TH ST NE	FRIDLEY	75,900	28,072	1,250	Plastic	3	54,737	30,670
51	97546958	RM - REPLACE ~850' 2" ST CL-2 49TH AVE N	FRIDLEY	73,100	25,265	1,150	Plastic	2	46,695	35,578
52	97590329	RM Bare steel project on Emerson Ave, N	RICHFIELD	59,000	8,422	2,837	Plastic	3	96,914	69,457
53	97591024	RM Bare steel project in Columbia Height	COLUMBIA HEIGHTS	187,000	11,229	2,628	Plastic	8	232,230	129,251
54	97591941	RM Bare Steel job in Columbia Heights. R	COLUMBIA HEIGHTS	147,000	11,229	3,502	Plastic	4	132,623	106,746
55	97830968	RM REPLACE SHORTED CASING ON 16" ST CL-2	MINNEAPOLIS	55,000	28,072	590	Plastic	8	*Reclassified as System Improvement*	
56	97940242	RM - BARE STEEL REPLACEMENT: REPLACE APP	BLOOMINGTON	184,000	42,108	700	Plastic	3	36,142	57,925
57	97940246	RM - BARE STEEL REPLACEMENT: REPLACE APP	GOLDEN VALLEY	111,000	168,432	1,400	Plastic	8	5,944	0
58	98536861	RM - BARE STEEL REPLACEMENT. AT REQUEST	LE SUEUR	37,000	126,324	400	Plastic	2	36,841	8,349
59										
60	Total			**$21,335,768**	**$5,906,349**	**171,651**			**$14,295,203**	**$4,433,089**

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case — Date of Request: 1/6/2022
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 1/19/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Engineering

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 9013	Subject: Bare Steel Main Replacement Project

Reference: Wiinamaki Workpaper 5 page 2

Complete the following table detailing the length of bare steel main replacement projects in the test year by replacement pipe size and material type.

Project ID	Existing bare steel length		Replacement mains				Services (number)
			Length	Material	Diameter		

Response:

Please see Attachment 1.

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480

CenterPoint Energy Minnesota Gas
Docket No. G-008/GR-21-435
Response to OAG IR #9013

The Company is in the process of planning the specific main replacements to be performed under the Bare Steel Main Replacement project in the test year. In contrast with transmission pipe projects, which are planned far in advance due to their engineering analysis and material procurement requirements, distribution main replacements are generally less complex, less expensive, and more numerous, and therefore require less advance planning. Factors that influence which and how many sections of bare steel will be replaced during the test year include segment-specific risk, system constraints related to co-occurring work, permitting, and actual year-to-date project costs compared to budget. As shown in the cited workpaper, the Company based its test year spending estimate on historic average unit costs per mile multiplied by the number of miles the Company estimates it will be able to replace within its project budget for the year. At this point in the year, the Company has prioritized projects to be designed* in 2022 and projects have been assigned to various engineers to finalize project scopes. The list below contains those projects for which complete designs exist. Additional designs will be completed in the coming months and additionally as the construction season proceeds and opportunities to add to the schedule arise.

* "Design" here refers to the creation of engineering drawings that specify the parts to be used, the proposed location of the new pipe, and construction procedures.

Order	Existing Bare Steel Length	Replacement Main Length	Replacement Main Material	Replacement Main Diameter	Number of Services
86303090	1,770	1,581	Plastic	4"	5
94489028	476	558	Plastic	3"	31
97071747	1,227	1,219	Plastic	2"	5
97102061	1,957	2,903	Plastic	2"/4"	1
97112189	1,160	2,068	Plastic	4"	10
97940246	1,221	1,386	Plastic	8"	6
97940248	3,526	6,766	Plastic	2"/4"	49
98672392	1,021	965	Plastic	4"	10
98678898	786	761	Plastic	2"	7
99711728	2,398	2,478	Plastic	3"	50
99844640	1,460	2,320	Plastic	2"	34
100174560	653	627	Plastic	3"	12
100352393	5,539	5,750	Steel	24"	0
100441627	634	648	Plastic	4"	2

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case — Date of Request: 1/6/2022
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 1/19/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Engineering

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 9014	Subject: Legacy Steel Main Replacement Project Reference: CPE response to OAG IR 9006, Attachment 1 Provide an updated version of the table included as Attachment 1 of CPE's response to OAG IR 9006 including both estimated and actual project costs. **Response:** Please see Attachment 1.

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480

CenterPoint Energy Minnesota Gas
Docket No. G-008/GR-21-435
Response to OAG IR #9014

The table below contains the same list of main projects that appeared in the Company's response to OAG IR #9006, which was itself an expanded version of the project list that appeared in Exhibit __ (JMW-WP) Sch. 2, Workpaper 6.

Costs include postings through December 31, 2021; costs are still being received on many 2021 work orders. Differences between estimated and actual costs occur because of projects being more or less complicated than anticipated, changes in project scope, and in particular with regard to service lines, the fact that the number of service lines attached to each main is estimated at an early point in the design process based on the engineer's general sense of the density of the area and without any information about the mix between residential and commercial customers.

Costs listed exclude construction overhead. Service line costs include any associated meter work.

Order #	Location	City	Est. Main Cost	Est. Svc. Cost	Main Length (ft)	Main Material	Main Diameter (in)	Actual Main Cost	Actual Svcs Cost	
97075850	40TH ST W	Minneapolis	$877,198	$145,373	5,055	Plastic	4	$1,261,972	$206,666	[1]
97405622	40TH ST W	Minneapolis	1,612,541	0	3,380	Steel	12	1,237,416	13,311	
97939469	COLFAX AVE N & GLENWOOD AVE	Minneapolis	1,155,574	0	1,200	Steel	24	1,052,894	0	
98553437	40TH ST E	Minneapolis	67,797	52,863	3,000	Steel	16	29,157	0	[2]
99511961	4 ST SE	Minneapolis	178,655	0	477	Steel	12	113,932	0	
			$3,891,764	$198,236	13,112			$3,695,371	$219,977	

[1] This work order was cancelled and replaced by order 100685772.
[2] Project not complete.

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case   Date of Request: 1/6/2022
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 1/19/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Engineering

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 9015	Subject: Legacy Steel Main Replacement Project

Reference: Wiinamaki Workpaper 6 page 1

Complete the following table detailing the length of legacy steel main replacement projects in the test year by replacement pipe size and material type.

Project ID	Existing legacy steel length		Replacement mains				Services (number)
			Length	Material	Diameter		

Response:

The Company is in the process of planning the specific main replacements to be performed under the Legacy Steel Main Replacement project in the test year. In contrast with transmission pipe projects, which are planned far in advance due to their engineering analysis and material procurement requirements, distribution main replacements are generally less complex, less expensive, and more numerous, and therefore require less advance planning. Factors that influence which and how many sections of legacy steel will be replaced during the test year include segment-specific risk, system constraints related to co-occurring work, permitting, and actual year-to-date project costs compared to budget. As shown in the cited workpaper,

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480

the Company based its test year spending estimate on historic average unit costs per mile multiplied by the number of miles the Company estimates it will be able to replace within its project budget for the year. At this point in the year, the Company has prioritized projects to be designed* in 2022 and projects have been assigned to various engineers to finalize project scopes. The design process is not yet complete for any legacy steel main replacements to be performed during the test year. These designs will be completed in the coming months and, potentially, as the construction season proceeds if opportunities arise to add to the schedule.

*"Design" here refers to the creation of engineering drawings that specify the parts to be used, the proposed location of the new pipe, and construction procedures.

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
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Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case — Date of Request: 1/6/2022
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 1/19/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Engineering

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.

OAG 9018

Subject: Legacy Plastic Main Replacement Project

Reference: Wiinamaki Workpaper 7 page 2, footnote 5

Complete the following table detailing the small (≤ 8" diameter) plastic mains installed in the Bare Steel Main Replacement project from 2015-2020 (inclusive).

Project ID	Main feet abandoned	City	Replacement mains				Replacement services		
			Length	Diameter	Cost		Replaced	Test + recon.	Cost

Response:

Please see Attachment 1.

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480

CenterPoint Energy Minnesota Gas
Docket No. G-008/GR-21-435
Response to OAG IR #9018

The cost of service line replacements was not considered in the comparison of average cost per foot of Minneapolis and non-Minneapolis bare steel main replacements. Service line costs exclude the cost of associated meter work.

			Replacement Main			Replacement Services		
Order	Total Footage Abandoned [1]	City	Footage Issued	Diameter (inches)	Cost [2]	# Replaced	# Test & Recon.	Cost [2]
62242219	2,465	RICHFIELD	3,013	8	$211,850	31	4	$141,915
70702371	4,620	ST LOUIS PARK	4,964	2	$126,640	98	4	$122,613
70741591	1,455	MINNEAPOLIS	1,432	2	$69,063	57	2	$100,581
71321826	2,422	WASECA	1,636	2	$53,063	32	8	$58,196
71457719	741	BROOKLYN CTR	906	6	$50,034	0	1	$7
71460802	7,010	ST LOUIS PARK	8,133	2	$254,489	0	0	$0
71538566	12,086	SAINT PETER	9,052	3	$300,083	101	14	$272,157
71568803	1,811	MINNETONKA	2,657	3	$56,560	22	11	$60,099
71601876	1,898	HOPKINS	2,047	6	$195,926	0	1	$1,661
72256050	8,032	WASECA	6,400	8	$302,204	26	15	$62,281
72256193	10,093	WASECA	8,780	2	$177,710	121	12	$181,533
72407270	7,013	WASECA	7,026	4	$211,317	50	22	$82,624
72408276	6,120	WASECA	6,292	2	$200,339	81	40	$117,241
72815032	3,346	ST LOUIS PARK	3,048	6	$103,270	58	8	$87,785
72855767	3,552	MINNEAPOLIS	3,478	2	$330,564	35	14	$135,891
72859174	2,183	ST LOUIS PARK	2,275	2	$49,148	51	12	$63,601
72874202	1,588	MINNETONKA	1,706	2	$34,676	17	5	$36,457
72878509	1,639	ST LOUIS PARK	1,676	2	$139,370	22	9	$47,787
72887615	619	ST LOUIS PARK	720	3	$22,004	0	0	$0
72930674	3,341	MINNEAPOLIS	4,305	3	$169,242	56	11	$83,326
73035942	13,734	LE SUEUR	11,000	2	$310,469	212	4	$370,979
73054666	5,561	LE SUEUR	4,840	2	$89,327	8	0	$14,343
73083899	19,219	LE SUEUR	14,187	6	$561,320	173	15	$305,964
73152852	2,371	ST LOUIS PARK	2,992	3	$78,221	48	5	$82,214
73157728	2,575	HOPKINS	2,739	3	$77,702	31	12	$59,396
73907423	1,023	ST LOUIS PARK	1,098	2	$24,550	9	7	$11,121
74069861	433	MANKATO	561	2	$24,065	4	0	$6,695
74295245	1,606	ST LOUIS PARK	1,650	2	$247,324	2	0	$12,076
74592664	269	RICHFIELD	280	3	$1,097	0	0	$0
75111536	2,934	DEEPHAVEN	3,000	2	$71,512	6	14	$47,741
75140505	1,312	BROOKLYN PARK	1,400	2	$41,476	10	5	$11,357
75151660	2,208	MINNEAPOLIS	2,400	8	$1,159,357	21	11	$157,322
75157229	1,331	ST LOUIS PARK	1,417	2	$71,532	53	1	$74,246
75175151	1,701	MINNETONKA	1,911	6	$110,440	18	7	$33,283
75225042	3,483	GREENWOOD	3,456	4	$75,387	30	17	$76,370
75306466	4,554	MINNEAPOLIS	5,153	6	$288,390	65	1	$161,148
75502099	628	BLOOMINGTON	660	3	$21,081	27	7	$64,053
75553966	755	MINNETONKA	905	3	$35,097	0	2	$1,945
75687516	5,564	HOPKINS	6,174	2	$164,668	118	20	$186,663
76033789	1,914	ST LOUIS PARK	2,000	3	$100,680	66	11	$174,861
76060809	1,278	BLOOMINGTON	1,296	2	$41,963	25	3	$24,422
76174573	629	NORTH MANKATO	626	4	$34,578	11	7	$24,208
76470337	1,802	ST LOUIS PARK	1,960	3	$104,548	45	10	$169,030
76587817	1,955	ST LOUIS PARK	2,152	3	$79,214	43	28	$88,725
76748406	3,351	ST LOUIS PARK	3,857	3	$358,307	67	12	$141,842
77947354	4,518	BLOOMINGTON	2,460	2	$82,425	28	9	$55,148

78071874	280	EDINA	318	3	$17,119	0	1	$753
78734232	1,378	MINNEAPOLIS	1,450	2	$59,627	28	1	$48,532
78963127	3,465	MINNEAPOLIS	4,001	2	$122,110	68	9	$96,326
79069799	2,366	NEW PRAGUE	550	2	$20,336	17	1	$2,216
79079354	7,944	SAINT PETER	6,746	2	$207,782	82	11	$157,249
79148204	599	MINNETONKA	700	3	$24,058	8	2	$10,698
79175214	5,294	SAINT PETER	5,650	2	$110,163	63	10	$79,759
79180248	1,424	HASTINGS	1,600	2	$41,659	16	11	$22,408
79329187	2,465	EDINA	2,568	2	$96,523	10	9	$20,087
79338947	6,367	BROOKLYN PARK	6,660	4	$131,397	0	0	$0
79340598	3,491	ST LOUIS PARK	3,709	2	$107,294	101	21	$324,347
80088392	6,611	WASECA	5,370	2	$111,168	24	10	$78,700
80136563	2,234	ST LOUIS PARK	2,319	2	$77,888	64	6	$234,935
80230508	2,630	WOODVILLE TWP	2,771	2	$314,111	19	1	$119,095
80245305	1,827	MINNEAPOLIS	1,889	8	$214,743	30	2	$45,476
80329944	12,168	LE CENTER	9,809	6	$281,770	104	29	$309,021
80338354	2,400	MINNETONKA	2,452	2	$60,402	34	5	$48,313
80520813	1,403	ST LOUIS PARK	1,432	3	$45,386	42	5	$72,490
81020526	285	EDINA	299	3	$31,500	0	0	$0
81050191	10,726	LE CENTER	10,792	2	$297,516	81	11	$260,623
81256169	333	MINNEAPOLIS	327	2	$17,615	0	1	$790
81923180	439	RICHFIELD	534	4	$61,349	1	2	$4,305
82064978	1,544	BLOOMINGTON	1,724	3	$52,302	28	4	$60,206
82238757	1,336	ST LOUIS PARK	1,462	6	$80,636	37	1	$117,034
82363368	424	WAYZATA	416	3	$24,902	1	3	$3,036
82668992	2,708	WASECA	2,614	2	$64,881	25	14	$48,484
82743028	2,955	WASECA	1,508	3	$50,292	8	1	$72,018
82757075	4,799	WASECA	3,664	2	$124,488	59	24	$164,618
82987227	329	RICHFIELD	705	3	$30,957	0	0	$0
83023458	1,110	ST LOUIS PARK	1,110	2	$52,357	11	9	$49,408
83100397	1,219	BROOKLYN CTR	1,328	3	$50,939	13	9	$17,975
83439383	673	BROOKLYN CTR	690	2	$20,798	6	6	$24,922
83473637	851	BROOKLYN CTR	918	2	$22,452	9	6	$11,570
83529078	1,768	RICHFIELD	1,246	2	$23,496	7	5	$7,297
83545030	1,223	FRIDLEY	1,837	2	$45,119	0	0	$0
83578510	5,036	WASECA	3,808	3	$57,750	34	21	$88,353
83636624	96	DEEPHAVEN	120	3	$8,787	0	0	$0
84215321	479	CRYSTAL	693	4	$118,158	4	1	$18,013
84279590	548	RICHFIELD	617	3	$17,977	6	1	$8,061
84337378	14,861	SAINT PETER	12,248	2	$496,788	100	65	$368,551
85469929	1,810	MINNEAPOLIS	2,008	3	$136,170	28	1	$77,057
85540294	7,624	EDINA	7,962	2	$177,789	103	21	$140,440
86105542	1,334	BLOOMINGTON	1,532	2	$50,224	17	5	$36,866
86266080	891	ROBBINSDALE	900	4	$41,793	22	4	$36,868
86269473	2,510	SAINT PETER	2,584	2	$149,448	3	1	$1,457
86302348	1,152	BLOOMINGTON	1,196	3	$50,934	14	3	$29,361
86303396	2,641	WASECA	3,074	2	$151,370	24	17	$75,953
86303662	2,681	WASECA	2,632	2	$80,605	3	0	$5,069
86304554	2,312	EXCELSIOR	2,288	2	$185,373	34	9	$101,291
86304775	43,489	SAINT PETER	33,727	6	$1,948,187	301	107	$898,993
86304874	5,600	SAINT PETER	3,677	6	$392,612	28	20	$111,467
86353651	2,268	MINNETONKA	2,594	2	$90,530	8	21	$23,250
86762308	506	HASTINGS	595	2	$35,030	6	1	$31,405
86766984	2,344	RICHFIELD	2,516	6	$111,057	48	12	$82,913
86767774	837	BLOOMINGTON	838	2	$43,999	20	2	$28,300
86767876	3,405	RICHFIELD	3,573	3	$126,543	62	19	$136,147

87003930	1,276	BLOOMINGTON	1,390	2	$39,260	25	5	$51,363
87423087	689	BELLE PLAINE	1,318	2	$72,055	16	1	$81,143
87423285	5,404	BELLE PLAINE	5,992	2	$264,016	61	10	$160,330
87901908	2,717	MINNETONKA	3,160	3	$172,189	21	11	$77,520
88242078	1,209	BELLE PLAINE	1,138	2	$48,504	12	0	$28,977
88801017	8,006	SAINT PETER	6,287	2	$460,031	49	2	$59,138
89133666	5,010	MINNEAPOLIS	6,217	3	$739,015	22	4	$148,324
89176174	14,198	MONTGOMERY	17,377	2	$608,653	164	2	$214,068
89343214	26,960	NORTH MANKATO	22,791	2	$894,068	390	7	$865,279
89430870	2,211	FRIDLEY	2,300	2	$154,457	23	5	$62,186
89491042	567	ST LOUIS PARK	580	2	$37,052	22	0	$41,472
89706213	781	BELLE PLAINE	859	3	$32,370	1	0	$2,107
89770312	577	ST LOUIS PARK	627	2	$21,967	0	0	$0
89770477	2,465	ST LOUIS PARK	1,651	2	$61,647	23	3	$58,155
90355256	100	MINNEAPOLIS	3,981	2	$215,685	108	5	$293,182
91182444	2,198	FRIDLEY	1,143	3	$95,427	17	16	$81,767
91208367	1,540	MINNETONKA	1,724	3	$45,363	0	19	$22,716
91447850	459	ST LOUIS PARK	484	3	$43,336	5	2	$23,547
91936504	2,152	MANKATO	3,687	2	$113,545	29	8	$83,524
92053137	21,793	MANKATO	16,684	2	$961,704	204	92	$657,504
92697266	431	LE SUEUR	873	2	$39,975	1	0	$13,308
92774672	223	MANKATO	248	2	$35,286	2	3	$11,307
93085622	3,070	COLUMBIA HEIGHTS	3,323	2	$162,954	43	6	$109,672
93552718	1,239	EXCELSIOR	1,684	2	$164,434	2	10	$31,231
94355235	809	MINNEAPOLIS	1,612	3	$162,943	22	2	$51,733
94441824	365	MINNEAPOLIS	385	3	$87,474	2	3	$23,891
94487435	2,070	ST LOUIS PARK	2,289	3	$128,467	43	21	$158,862
94487447	3,001	MANKATO	3,147	2	$130,741	45	3	$124,334
94488455	2,081	EDINA	1,984	6	$269,320	2	5	$45,919
94490993	605	FRIDLEY	746	2	$61,503	10	3	$42,852
95566778	5,174	MANKATO	2,659	2	$104,773	0	0	$0

[1] Main replaced under order 89770477 was abandoned under order 86218703.

[2] Excluding construction overhead

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case — Date of Request: 1/12/2022
Requested From: CenterPoint Energy Minnesota Gas — Response Due: 1/25/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Engineering

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 9022	Subject: Historic transmission pipeline costs Separately for each year from 1960 through 2021 (inclusive), provide the total length (in feet) of transmission pipeline installed by the Company in its Minnesota service area and the total installation costs. If cost data is not available from 1960, begin with the most recent year for which the Company has data. **Response:** After examining the information requested in this response, CenterPoint Energy is only able to provide data beginning with the year 2017. This is the first-year reportable asset addition quantities were available in the Company's SAP-ALA Asset Module system. Providing addition quantities for mains and services prior to 2017 necessitates a completely manual process of analyzing individual work orders to determine materials issued to each work order in each year. The SAP-ALA Asset Module was a new system in 2017 and is the Company's Enterprise Resource Planning (ERP) accounting module utilized for recording and reporting on the Company's fixed assets. Further, this system categorizes transmission pipe within the distribution function (FERC 376). Please reference the Company's response in OAG 9023 that provides combined transmission and distribution data in the manner requested beginning in 2017.

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
Minnesota Office of the Attorney General

Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case   Date of Request: 1/12/2022
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 1/25/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Engineering

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 9023	Subject: Historic distribution main costs

Separately for each year from 1960 through 2021 (inclusive), provide the total length (in feet) of distribution mains installed by the Company in its Minnesota service area and the total installation costs. If cost data is not available from 1960, begin with the most recent year for which the Company has data.

Response:

After examining the information requested in this response, CenterPoint Energy is only able to provide data beginning with the year 2017. This is the first-year reportable asset addition quantities were available in the Company's SAP-ALA Asset Module system. Providing addition quantities for mains and services prior to 2017 necessitates a completely manual process of analyzing individual work orders to determine materials issued to each work order in each year. The SAP-ALA Asset Module was a new system in 2017 and is the Company's Enterprise Resource Planning (ERP) accounting module utilized for recording and reporting on the Company's fixed assets. Further, this system categorizes transmission pipe within the distribution function (FERC 376). The table below provides combined transmission and distribution data in the manner requested beginning in 2017.

Mains FERC 376	2017	2018	2019	2020	2021
Total Cost	$144,166,092	$100,636,432	$174,346,296	$129,157,437	$168,357,051
Feet	1,419,537	1,123,210	1,519,979	1,280,055	2,027,769

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480

*Each year excludes work orders at completed construction not classified Account 106.

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480

State of Minnesota
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Utility Information Request

Docket Number: G-008/GR-21-435 - 2021 MN Rate Case   Date of Request: 1/12/2022
Requested From: CenterPoint Energy Minnesota Gas   Response Due: 1/25/2022

Analyst Requesting Information: Andrew Twite

Type of Inquiry: Engineering

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
OAG 9024	Subject: Historic service line costs Separately for each year from 1960 through 2021 (inclusive), provide the total number of service lines installed by the Company in its Minnesota service area and the total installation costs. If cost data is not available from 1960, begin with the most recent year for which the Company has data. **Response:** After examining the information requested in this response, CenterPoint Energy is only able to provide data beginning with the year 2017. This is the first-year reportable asset addition quantities were available in the Company's SAP-ALA Asset Module system. Providing addition quantities for mains and services prior to 2017 necessitates a completely manual process of analyzing individual work orders to determine materials issued to each work order in each year. The SAP-ALA Asset Module was a new system in 2017 and is the Company's Enterprise Resource Planning (ERP) accounting module utilized for recording and reporting on the Company's fixed assets. The table below provides data in the manner requested beginning in 2017.

Services FERC 380	2017	2018	2019	2020	2021
Total Cost	$40,596,792	$35,061,159	$47,269,778	$29,607,935	$61,372,356
Service Count	19,837	16,517	20,766	12,374	22,245

*Each year excludes work orders at completed construction not classified Account 106.

Response By: John Wiinamaki
Title: Director, Engineering - Gas MN
Department: Minnesota Gas Engineering
Telephone: Drew Sudbury: 612-321-4480