BEFORE THE NEBRASKA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF BLACK HILLS NEBRASKA GAS, LLC, D/B/A BLACK HILLS ENERGY, RAPID CITY, SOUTH DAKOTA, SEEKING APPROVAL OF A GENERAL RATE INCREASE	**)**	**APPLICATION NO. NG-109**

DIRECT TESTIMONY OF

THOMAS J. SULLIVAN, JR.

ON BEHALF OF

BLACK HILLS NEBRASKA GAS, LLC

June 1, 2020

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Thomas J. Sullivan, Jr., 15898 Millville Road, Richmond, Missouri 64085.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am President and owner of Navillus Utility Consulting LLC ("Navillus").

Q. HOW LONG HAVE YOU BEEN WITH NAVILLUS UTILITY CONSULTING?

A. I started the company in June 2011.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I received a Bachelor of Science Degree in Civil Engineering Summa Cum Laude from the University of Missouri - Rolla in 1980 and a Master of Business Administration Degree in Business Administration from the University of Missouri - Kansas City in 1985.

Q. ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A. Yes, I am a Registered Professional Engineer in the State of Missouri.

Q. TO WHAT PROFESSIONAL ORGANIZATIONS DO YOU BELONG?

A. I am a member of the American Society of Civil Engineers.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. Prior to forming Navillus, I worked for Black & Veatch Corporation. I worked for Black & Veatch for over 31 years as an engineer, project engineer, project manager, vice president, and director. I have been responsible for the preparation and presentation of numerous studies for gas, electric, water, and wastewater utilities. My clients served

include investor-owned utilities, publicly owned utilities, and their customers. The professional studies that I have prepared involve valuation and depreciation, cost of service, cost allocation, rate design, cost of capital, supply analysis, load forecasting, economic and financial feasibility, cost recovery mechanisms, and other engineering and economic matters.

Q. HAVE YOU PREVIOUSLY APPEARED AS AN EXPERT WITNESS?

A. Yes, I have. In Exhibit No. TJS-1, I list cases where I have filed expert witness testimony. As noted on that attachment, I have appeared before the Nebraska Public Service Commission ("Commission") in the following cases:

- Aquila Networks, Commission Application Nos NG-0001, NG-0002, and NG-0003 regarding weather normalization.
- Kinder Morgan, Inc., Commission Application No. NG-0036 regarding weather normalization adjustment, test year billing determinants, revenues under existing rates, customer usage trends, and rate design.
- Aquila Networks, Commission Application No. NG-0041 regarding natural gas utility jurisdictional and Class Cost of Service Study ("CCOSS"), rate design, and revenue synchronization adjustment.
- SourceGas Distribution, LLC, Commission Application No. NG-0060 regarding customer and usage trends, weather normalization adjustment, customer change adjustment, use per customer adjustment, inflation adjustment, and competitive factors.

- Black Hills/Nebraska Gas Utility, LLC, Commission Application No. NG-0061 regarding natural gas utility jurisdictional and class cost of service study, rate design, and revenue synchronization adjustment.
- SourceGas Distribution, LLC, Commission Application No. NG-0067 regarding natural gas utility jurisdictional and class cost of service study, rate design, customer and usage trends, number of customer change adjustment, use per customer adjustment, and competitive factors.

All these rate reviews were for either BH Gas Utility (formerly Black Hills/Nebraska Gas Utility Company, LLC) or BH Gas Distribution (formerly SourceGas Distribution). Commission Application Nos. NG-0061 and NG-0067 were the last Nebraska general rate reviews for BH Gas Utility and BH Gas Distribution, respectively.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS RATE REVIEW PROCEEDING?

A. I am testifying on behalf of Black Hills Nebraska Gas, LLC ("BH Nebraska Gas" or "Company") d/b/a Black Hills Energy. BH Nebraska Gas is the Nebraska natural gas utility resulting from the recent consolidation of the Nebraska gas utility assets and operations of Black Hills/ Nebraska Gas Utility Company, LLC ("BH Gas Utility") and Black Hills Gas Distribution, LLC ("BH Gas Distribution").[1]

[1] *See* Nebraska Public Service Commission Application No. NG -100.

Q. WHAT IS THE NATURE OF YOUR WORK IN THIS ENGAGEMENT?

A. The Company asked me to:

1. Discuss the history of the jurisdictional and class cost of service studies for the BH Gas Utility and BH Gas Distribution systems.
2. Prepare a CCOSS based on BH Nebraska Gas' proposed Pro Forma Period revenue requirement.
3. Discuss the history behind the current BH Gas Utility and BH Gas Distribution jurisdictional rate designs.
4. Discuss competitive issues for BH Nebraska Gas relative to Nebraska electric utilities.
5. Develop cost-based rates based on the results of the CCOSS.
6. Design rates proposed by BH Nebraska Gas which will produce revenues equal to BH Nebraska Gas' proposed Pro Forma Period jurisdictional revenue requirement.

All these analyses are based on a Pro Forma Period ending December 31, 2020, unless otherwise indicated in my testimony. After this initial introductory section, my direct testimony will follow the six parts listed above.

Q. DO YOU SPONSOR ANY EXHIBITS?

A. Yes. I sponsor the following Exhibits:

Application Exhibits

Application Exhibit No. 1

Section 1, Schedule B2	Bill Impacts – Existing Rates, Proposed Rates, and Alternate Rates
Section 4, Exhibit A	Functionalization and Classification of Rate Base and Cost of Service
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Q. PRIOR TO BEGINNING YOUR DISCUSSION OF THE HISTORY OF THE LEGACY COMPANIES OF BH NEBRASKA GAS, CAN YOU PLEASE PROVIDE A SUMMARY OF THE VARIOUS ENTITIES TO WHICH YOU WILL BE REFERRING?

A. Yes. The table below summarizes the legacy companies that comprise BH Nebraska Gas including names under which they have done business in Nebraska that I will be referencing throughout my direct testimony and exhibits.

Table TJS-1 - Summary of BH Nebraska Gas Legacy Systems

Black Hills Nebraska Gas	
BH Gas Utility	**BH Gas Distribution**
Black Hills/Nebraska Gas Utility Company	SourceGas Distribution
Aquila, Inc. or Aquila Networks	Kinder Morgan
UtiliCorp United, Inc.	KN Energy, Inc.
Peoples Natural Gas Company	Kansas-Nebraska Natural Gas Company

II. BACKGROUND CCOSS DISCUSSION

Q. DID YOU SPONSOR THE JURISDICTIONAL AND CCOSS AND RATE DESIGN FOR THE TWO BH NEBRASKA GAS SYSTEMS IN THEIR LAST TWO RATE CASES?

A. Yes. The current base rates for BH Gas Utility resulted from Commission Application No. NG-0061 which was based on a test year ended July 31, 2009. I sponsored both the jurisdictional and CCOSS and rate design in that proceeding. The current base rates for the BH Gas Distribution (formerly SourceGas Distribution) system resulted from Commission Application No. NG-0067 which was based on a test year ended March 31, 2011. I also sponsored both the jurisdictional and CCOSS and rate design in that proceeding.

Q. WERE THE JURISDICTIONAL AND CLASS COST OF SERVICE STUDIES YOU SPONSORED ADOPTED BY THE COMMISSION IN BOTH OF THOSE PROCEEDINGS?

A. Yes. In Commission Application No. NG-0061, the Commission approved the jurisdictional and CCOSS I sponsored with my rebuttal testimony. The changes I made based on Public Advocate recommendations and that were reflected in my rebuttal testimony and exhibits were accepted by the Commission as discussed on Pages 36 through 39 of the Commission's Final Order dated August 17, 2010. In Commission Application

No. NG-0067, the Commission approved the jurisdictional and CCOSS I sponsored in that case as stated on Page 26 of the Commission's Order Granting Application in Part dated May 22, 2012.

Q. WERE THE JURISDICTIONAL AND CLASS COST OF SERVICE STUDIES YOU SPONSORED IN BOTH OF THOSE PROCEEDINGS PREPARED USING THE SAME METHODOLOGIES?

A. Yes. The study I sponsored in Commission Application No. NG-0067 was specifically developed to mirror the study from Commission Application No. NG-0061. The primary difference between the two studies are attributable to the differences in the assets and customer make-up of the two systems that I discuss later in my testimony. I used the same approaches to functionalize and classify costs and to allocate those costs to customer classes that I discuss in the next section of my testimony.

Q. PLEASE DISCUSS THE ORIGIN OF THE METHODOLOGY YOU USED IN THOSE LAST TWO RATE CASES.

A. The model and approach used for the jurisdictional and class cost of service studies I sponsored in those cases originate from the BH Gas Utility (formerly Aquila, Inc.) rate case in Commission Application No. NG-0041. I sponsored the jurisdictional and CCOSS in that case. The CCOSS I sponsored in that case was based on a test year ended June 30, 2006 and was based on the BH Gas Utility system I discuss in my testimony.

Q. AS IT PERTAINS TO THIS STUDY, WHAT DID THE COMMISSION FIND IN COMMISSION APPLICATION NO. NG-0041?

A. There were several important findings by the Commission in that case related to the jurisdictional and CCOSS I sponsored in that case including:

1. The Commission approved the consolidation of the three jurisdictional rate areas into a "Nebraska-wide rate". (See Page 23 of the Order Granting Application in Part dated July 24, 2007).
2. On Page 26 of the same Order, the Commission approved the direct assignment of investment to certain directly served customers and approved the classification and allocation of mains reflected in the CCOSS I sponsored.
3. Also, on Page 26 of this Order, the Commission ordered BH Gas Utility to:
   a. further analyze the issue addressed in item 2 above; and
   b. address the reasons for a consolidated cost of service study.
4. On Page 27 of this Order, the Commission approved the allocation of meters and regulators in the CCOSS I sponsored.
5. On Page 28 of this Order, the Commission approved a series of corrections that I made to the cost of service study in my rebuttal testimony and approved the other cost allocation issues not otherwise specified.
6. On Page 28 of this Order, the Commission approved the jurisdictional revenue requirement resulting from the CCOSS I sponsored with the corrections identified in Item 5 above.
7. On Pages 28-29 of this Order, the Commission ordered BH Gas Utility to include both the total Nebraska and jurisdictional amounts related to the BH Gas Utility's revenue requirement in its next rate review.

Q. WHAT WAS THE APPLICATION FOR THE NEXT BH GAS UTILITY RATE REVIEW?

A. It was Commission Application No. NG-0061. I sponsored the jurisdictional and CCOSS for BH Gas Utility in that case.

Q. DID THE JURISDICTIONAL AND CCOSS YOU SPONSORED IN COMMISSION APPLICATION NO. NG-0061 REFLECT THE ITEMS THAT BH GAS UTILITY WAS ORDERED TO ADDRESS IN THE COMMISSION'S ORDER IN COMMISSION APPLICATION NO. NG-0041?

A. Yes. The CCOSS provided in Commission Application No. NG-0061 provided further analysis regarding the direct assignment of investment and resulted in a reduction in the amount of investment directly assigned limiting that direct assignment to only one customer (Cargill). The test for directly assigning plant investment was narrowed in that case to only include customers that met the following criteria:

1. The customer was directly connected to the interstate pipeline serving BH Gas Utility and did not have any of its gas delivered through the remainder of BH Gas Utility's transmission or distribution system.
2. The facilities and investment (net of any customer contribution) could be determined from BH Gas Utility's records.

The remainder of the mains investment was classified and allocated using the same methodology used in Commission Application No. NG-0041.

Also, the CCOSS provided in Commission Application No. NG-0061 was based on the consolidation of all the jurisdictional rate areas and included the additional detail ordered in Item 7 in the prior answer above.

Q. WHAT WERE THE SIGNIFICANT FINDINGS OF THE COMMISSION IN COMMISSION APPLICATION NO. NG-0061 RELATED TO THE CCOSS YOU SPONSORED IN THAT CASE?

A. There were several important findings by the Commission in Commission Application No. NG-0061 related to the jurisdictional and CCOSS I sponsored in that case including:

1. On page 35 of the Final Order Granting the Application in Part, the Commission acknowledged the changes I made relative to the Order in the prior case.
2. On page 36 of the same Order, the Commission approved the allocation of mains that I proposed including the direct assignment customers.
3. On page 37 of that Order, the Commission approved a change to the classification of compressor station equipment and the allocation of forfeited discounts that I made in my rebuttal testimony based on the recommendation of the Public Advocate.
4. On pages 37 and 38 of that Order, the Commission approved BH Gas Utility's position on all the other contested issues related to the CCOSS.

Q. PLEASE PROVIDE SOME BACKGROUND DISCUSSION OF CCOSS ON THE BH GAS DISTRIBUTION SYSTEM.

A. Even though I testified in the SourceGas Distribution rate case in Commission Application No. NG-0060, I did not sponsor or testify to the CCOSS BH Gas Distribution filed in that case. That case was based on a test year ended December 31, 2008, so chronologically that case was filed after the BH Gas Utility rate review in Commission Application No. NG-0041 and before the BH Gas Utility rate review in Commission Application No. NG-0061. In its Order Granting Application in Part in the SourceGas Distribution Commission

Application No. NG-0060 rate review proceeding, the Commission stated: "The Commission will expect SourceGas in the future to provide evidence regarding the cost of service to all classes of ratepayers in order to ensure that no subsidy exists."

The CCOSS provided by SourceGas in Commission Application No. NG-0060 did not develop a jurisdictional allocation to determine the cost of service of both the jurisdictional and non-jurisdictional customers. In the proceeding, the Commission and Public Advocate were concerned that the jurisdictional customers were subsidizing the non-jurisdictional customers. This was the issue that the Commission ordered SourceGas to address in its next rate review application.

Q. WHEN DID SOURCEGAS FILE ITS NEXT RATE REVIEW?

A. SourceGas' next rate review proceeding was Commission Application No. NG-0067, which was based on a test year ended March 31, 2011. Chronologically, this case was filed after the BH Gas Utility case filed in Commission Application No. NG-0061.

Q. DID YOU SPONSOR THE JURISDICTIONAL AND CCOSS IN COMMISSION APPLICATION NO. NG-0067?

A. Yes.

Q. PLEASE GENERALLY DESCRIBE THE JURISDICTIONAL AND CCOSS YOU SPONSORED IN COMMISSION APPLICATION NO. NG-0067.

A. The study I filed in Commission Application No. NG-0067 was based on the methodologies and models I used in the BH Gas Utility case filed in Commission Application No. NG-0061 consistent with the Commission's order in Commission Application No. NG-0061. The methodologies and models I had previously sponsored for the BH Gas Utility met the Commission's requirement in Commission Application No.

NG-0060 that SourceGas file a CCOSS in its next rate case with sufficient detail that would allow the Commission to determine whether the jurisdictional customers were subsidizing the non-jurisdictional customers.

Q. WHAT WERE THE PRIMARY DIFFERENCES BETWEEN THE JURISDICTIONAL AND CCOSS YOU SPONSORED IN COMMISSION APPLICATION NO. NG-0067 AND COMMISSION APPLICATION NO. NG-0061?

A. There were two significant differences between the two studies that reflected significant differences between the BH Gas Distribution and BH Gas Utility systems. First, the BH Gas Distribution system was formerly part of the vertically integrated Kinder Morgan (and prior to that K N Energy) system which prior to FERC Order No. 636 included natural gas supply, gathering, storage, transmission and distribution facilities. The BH Gas Utility system was also once a part of Northern Natural Gas Company ("Northern"). The distribution company division of Northern (i.e., "Peoples Natural Gas Company") was separated from Northern's upstream assets and sold in 1986 to UtiliCorp United Inc. (UtiliCorp United, Inc. was later renamed as Aquila, Inc.).[2] The sale of the distribution assets of Aquila's Peoples Natural Gas Company occurred prior to the issuance of FERC Order 616. Thus, the BH Gas Utility system never had these upstream assets.

As part of Kinder Morgan's compliance with Order No. 636, the distribution systems in Nebraska were separated from the upstream assets. However, the Kinder Morgan/KN Energy system had significant transmission facilities in Nebraska that were essentially lateral lines used to connect all the town distribution systems to the main transmission facilities. These transmission lateral lines were included with the distribution

[2] In 2008, Aquila, Inc. sold local distribution company assets to Black Hills Corporation in 2008. *See, Commission Application NG–0044.*

assets that were spun down to the Kinder Morgan distribution company that was ultimately sold and became SourceGas Distribution. Thus, the BH Gas Distribution system had substantial investment in mains that serve a transmission function as will be discussed in the next section of my direct testimony. Compared to the BH Gas Utility system, the BH Gas Distribution system had significantly more investment in mains that I classify as serving a transmission (versus distribution) function as defined in the next section of my direct testimony.

Second, customer composition of the BH Gas Distribution system was different. The BH Gas Distribution system had significantly more large volume non-jurisdictional customers who met the definition of direct served customers discussed earlier in my direct testimony. The BH Gas Distribution system had direct served customers who were directly connected to interstate pipelines and thus were not served from either the SourceGas transmission or distribution assets. Further, the BH Gas Distribution systems had direct served customers who were directly connected to the Kinder Morgan transmission system that were spun down to SourceGas and were thus served from the SourceGas assets that provide a transmission function but not assets that serve a distribution function. Finally, the BH Gas Distribution system had a significant non-jurisdictional agricultural load that primarily served irrigation customers. While the methodology used to functionalize and allocate mains for the BH Gas Distribution CCOSS was the same as that used for the BH Gas Utility system, the specific results were different due to the different assets and non-jurisdictional customer classes.

Q. WHAT WERE THE SIGNIFICANT FINDINGS OF THE COMMISSION IN COMMISSION APPLICATION NO. NG-0067 RELATED TO THE CCOSS YOU SPONSORED IN THAT CASE?

A. As stated on Page 26 of the Commission's Order Granting Application in Part dated May 22, 2012: "the COSS should be approved".

Q. DOES THE JURISDICTIONAL AND CCOSS YOU SPONSOR IN THE CURRENT CASE USE THE SAME METHODOLOGIES AND ALLOCATIONS USED IN THOSE PRIOR CASES?

A. Yes. As will be discussed in the next section of my direct testimony, the methodologies used to functionalize and classify costs in the most recent BH Gas Utility and BH Gas Distribution models were virtually the same and that same methodology is used in the current filing. As discussed earlier, the BH Gas Utility and BH Gas Distribution systems have different jurisdictional and non-jurisdictional classes, so the model used in the current case reflects the jurisdictional classes proposed in this case, a merger of similar non-jurisdictional classes and a new non-jurisdictional class reflecting services being provided today that were not provided in the last rate reviews. The methodologies used to develop the allocation bases were consistent between the last BH Gas Utility and BH Gas Distribution jurisdictional and class cost of service studies, and the consolidated study provided in the current review uses the same allocation bases as was used in the last rate reviews. The primary differences between the two cost of service models used in the prior rate reviews and the current review reflect the merging of the rate classes between the two systems. I discuss the rate classes in more detail in the next section of my direct testimony.

III. CLASS COST OF SERVICE STUDY

Q. WHAT IS THE PURPOSE OF THE CCOSS?

A. A CCOSS is intended to determine the cost of providing service to the various customer classes served by the utility. The customer classes are defined as relatively homogeneous groups of customers whose usage characteristics and service requirements are similar. The classes generally align with the various rates the utility charges for service. The costs allocated to the customer classes consist of the various components of rate base and revenue requirements. The primary component of rate base is the net plant investment in the facilities of the utility system (i.e. mains, service lines, meters and regulators, etc.). Revenue requirements primarily consist of operation and maintenance expenses, depreciation expenses, return on rate base, and taxes.

For BH Nebraska Gas, the CCOSS is also a jurisdictional cost of service study that is used to determine the jurisdictional customer revenue requirement and revenue deficiency. The CCOSS is used as a tool or as one of the principle considerations in the design of the rates charged by the utility; in this case, the rates for the jurisdictional customers. While a CCOSS does provide the overall cost of service or overall revenue requirement for each customer class, the real value of the CCOSS is providing detail regarding the cost of the various functions or services that the utility provides. Further, rates generally consist of fixed and variable components that target specific fixed and variable costs. Fixed costs are costs that do not vary with the amount of the product produced or used. Variable costs are costs that do vary directly with the amount of product produced or used. To the extent practical, rates should be designed to reflect the fixed and variable nature of the underlying costs.

Q. HAVE YOU PREPARED THE JURISDICTIONAL AND CCOSS TO WHICH YOU REFER?

A. BH Nebraska Gas prepared the CCOSS under my direction and supervision, and I am sponsoring the CCOSS. The CCOSS is contained in Application Exhibit No. 1, Section 4, Exhibits A and B.

Q. PLEASE GENERALLY DESCRIBE THE JURISDICTIONAL CCOSS.

A. The CCOSS is based upon BH Nebraska Gas operations for the Pro Forma Period ending December 31, 2020. The CCOSS is based on the consolidation of all the BH Nebraska Gas utility gas systems into one total Nebraska system. The BH Nebraska Gas utilities include the BH Gas Utility and BH Gas Distribution systems. The consolidation of these gas distribution systems is discussed more fully in the Direct Testimony of Mr. Amdor and Mr. Jarosz.[3]

My CCOSS consists of two steps. In the first step costs are classified to functional categories. In the second step the classified costs are then allocated to customer classes.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY FUNCTIONAL CATEGORIES.

A. In the context of BH Nebraska Gas' CCOSS, the term function or functional refers to the broad services provided by a natural gas distribution utility that include transmission, distribution, and customer-related activities. These functions generally parallel the cost functions used in the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts.

[3] *See also, Commission Application NG-100.*

Q. PLEASE EXPLAIN WHAT YOU MEAN BY CLASSIFY OR CLASSIFICATION.

A. In the context of BH Nebraska Gas' CCOSS, classification consists of assigning or allocating costs to demand or capacity-related costs, commodity-related costs, and customer-related costs. Demand or capacity-related costs are those costs that are incurred or that vary with the peak period requirements of the system which occur during the winter heating season. Commodity-related costs are costs that vary with the volumes that are delivered throughout the year. Customer-related costs are those costs that vary with the number of customers connected and/or served.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY ALLOCATED OR ALLOCATION.

A. In the context of BH Nebraska Gas' CCOSS, allocation refers to the allocations of the functionally classified costs to specific customer classes using allocation bases that represent each class' relative cost responsibility for the costs being allocated. For example, demand or capacity-related costs are allocated to customer classes on their relative portion of peak period (either peak day or peak season) volumes. Further, the allocations reflect the fact that not all customers utilize all the functions (transmission and distribution) provided by BH Nebraska Gas.

A. <u>Functionalization and Classification</u>

Q. PLEASE DESCRIBE APPLICATION EXHIBIT NO. 1, SECTION 4, EXHIBIT A.

A. In Application Exhibit No. 1, Section 4, Exhibit A, I classify costs into functional categories. Application Exhibit No. 1, Section 4, Exhibit A consists of the following four tables:

- Table 1 - Functional Classification of Rate Base and Cost of Service;
- Table 2 – Functional Classification of Rate Base;

- Table 3 – Functional Classification of Operations and Maintenance; and
- Table 4 –Functional Classification of Other Cost of Service Components.

Q. PLEASE GENERALLY DESCRIBE THE FUNCTIONALIZATION AND CLASSIFICATION STEPS.

A. In the CCOSS, I classify costs into the following functions: supply, transmission - demand and commodity, distribution - demand, commodity and customer, services (service lines), meters and regulators, customer accounts, and direct assignments.

Q. PLEASE GENERALLY DESCRIBE HOW YOU CLASSIFY COSTS WITHIN THE VARIOUS FUNCTIONS.

A. I classify the gas supply portion of cash working capacity as supply-related costs. Generally, one-half of fixed transmission-related costs are classified as Transmission-Demand (capacity) and one-half as Transmission-Commodity. Variable transmission-related costs which include load dispatching costs are classified as Commodity. This classification also includes the former BH Gas Distribution transmission mains that are now booked to distribution mains. This classification is discussed in detail in Exhibit No. TJS-2.

The classification of distribution mains is based on a study of the BH Nebraska Gas investments and the relative capacity of these facilities that is discussed in detail in Exhibit No. TJS-2 between Distribution-Demand, Distribution-Commodity, and Distribution-Customer. Jointly used distribution facilities other than mains (regulator stations, for example) are classified 50 percent to Distribution-Demand and 50 percent to Distribution-Commodity similar to how these facilities are classified for Transmission.

I classify costs associated with the service lines as Service lines-related costs.

I classify costs associated with meters and regulators as Meters and Regulators-related costs.

I classify customer accounting expenses as Customer Accounts-related costs.

Two-thirds of customer service and information expenses and sales expenses are classified as Customer Accounts-related costs. The remaining one-third are classified as Distribution Commodity-related costs and allocated on a volumetric basis.

There are three general categories of directly assigned costs. There are costs that are directly assigned to only Jurisdictional customers and two categories of costs that are directly assigned only to non-Jurisdictional customers as will be discussed in more detail later in my direct testimony.

Q. HOW ARE PLANT INVESTMENT COSTS FUNCTIONALIZED AND CLASSIFIED?

A. Plant investment costs are generally classified in the manner described above. Transmission plant is classified 50 percent to Transmission-Demand and 50 percent to Transmission-Commodity.

I classify 12.75 percent of the distribution mains plant as Transmission-related costs (the BH Gas Distribution transmission facilities discussed above) with one-half of these costs classified as Transmission-Demand related and one-half as Transmission-Commodity -related, the same classification used for transmission mains.

I classify the remaining 87.25 percent of distribution mains plant as Distribution-related costs with 12.6 percent serving a Transmission function and 87.4 percent serving a Distribution Function. I classified 50 percent of the Transmission function to Distribution-

Demand and 50 percent to Distribution-Commodity. I classify the remaining 87.4 percent serving the Distribution function with 40.6 percent classified as Distribution-Demand and 59.4 percent classified as Distribution-Customer. Thus, the overall distribution mains classification is 6.3 percent (12.6 percent x 50 percent) Commodity-related, 41.8 percent ((12.6 percent x 50 percent) + (87.4 percent x 40.6 percent)) Demand- (or capacity) related, and 51.9 percent (87.4 percent x 59.4 percent) customer-related. I discuss the development of this classification in Exhibit No. TJS-2 and the calculations are shown in Exhibit No. TJS-2, Schedule 2-1.

I classify the jointly used facilities other than distribution mains (measuring and regulating station equipment, for example) similarly to how the distribution mains that serve a transmission function with 50 percent classified as Distribution-Demand and 50 percent classified as Distribution-Commodity.

Plant investment in service lines and meters and regulators are classified to the Service and Meters and Regulators function, respectively. Other property on customers' premises is classified as Services. Other distribution plant is classified in the same manner as distribution mains.

All Plant investment associated with the Negotiated-Direct and Negotiated-Supply customers are directly assigned to those customers with the exception of Meters and Regulators which are allocated to those customers in the same manner as all other customers. This is also discussed in more detail in Exhibit No. TJS-2.

Q. HOW ARE GENERAL PLANT AND INTANGIBLE PLANT FUNCTIONALIZED AND CLASSIFIED?

A. With the exception of the billing system, general plant (e.g., land, structures, office furniture, other software and computers) and intangible plant are mostly associated with headquarters and/or service center types of activities, so this plant is functionalized and classified based on a category of costs called Supervised O&M (operation and maintenance expenses). Because Supervised O&M captures direct labor expenses, it constitutes an appropriate basis for classifying general plant and intangible plant.

Q. WHAT IS SUPERVISED O&M?

A. Supervised O&M primarily captures labor driven costs that are directly charged or assigned to transmission, distribution or customer specific distribution exclusive of A&G expenses. Supervised O&M costs are shown on Application Exhibit No. 1, Section 4, Exhibit A, Table 3, Line 85. Supervised O&M costs are equal to operation and maintenance expenses before administrative and general expenses and excluding rents, royalties and uncollectible accounts. These excluded items contain little or no direct BH Nebraska Gas labor expense.

Q. HOW ARE BILLING SYSTEM INVESTMENTS FUNCTIONALIZED AND CLASSIFIED?

A. The billing system costs in general plant are assigned to the customer accounting Function on Application Exhibit No. 1, Section 4, Exhibit A, Table 2, Line 57 because these investments are customer accounting and billing specific costs.

Q. HOW ARE THE OTHER RATE BASE ITEMS FUNCTIONALIZED AND CLASSIFIED?

A. Application Exhibit No. 1, Section 4, Exhibit A, Table 2, Column P, Lines 71 - 81, show how the other rate base items are functionalized and classified. The most significant of these items is Accumulated Deferred Income Taxes ("ADIT.") There are two components of ADIT, one component is directly attributable to jurisdictional customers and is allocated to the jurisdictional classes based on rate base. The remainder of ADIT is attributable to all customers and is functionalized and classified based on net plant. ADIT is a function of income or return, depreciation expenses, and income taxes, which for a regulated utility are all directly related to plant investment and/or return on investment.

Q. AFTER FUNCTIONALIZING AND CLASSIFYING RATE BASE, HOW DO YOU FUNCTIONALIZE AND CLASSIFY OPERATION AND MAINTENANCE AND GENERAL EXPENSES?

A. The functionalization and classification of operation and maintenance and general expenses are shown in Application Exhibit No. 1, Section 4, Exhibit A, Table 3. Generally, the operation and maintenance expenses associated with transmission and distribution are classified based on the underlying plant with which the costs are associated. For example, maintenance of distribution mains (Account 887) is classified in the same manner as distribution mains plant (Account 376).

As previously discussed, customer accounting expenses are classified as customer accounting expenses. Two-thirds of customer service and information expenses and sales expenses are classified as customer accounts-related costs. The remaining one-third are classified as distribution commodity-related costs and allocated on a volumetric basis. This

classification gives recognition that these activities serve individual customers and strive to increase system utilization (throughput and customers).

Administrative and general expenses are classified based on Supervised O&M as previously discussed with the exception of property insurance which is classified based on net plant and regulatory commission expense which is classified such that it is allocated based on total system throughput (distribution-commodity).

Q. HOW ARE DEPRECIATION EXPENSES AND TAXES OTHER THAN INCOME TAXES CLASSIFIED?

A. The classification of depreciation expenses and taxes other than income taxes are shown on Application Exhibit No. 1, Section 4, Exhibit A, Table 4.

Depreciation expenses are classified based on how the underlying plant functions are classified. For example, distribution plant depreciation expenses are classified based on the resulting classification of total distribution plant.

Ad valorem taxes (property taxes), Line 10, are classified based on net plant because property tax expenses are directly related to the level of plant investment and more specifically the assessed value of those facilities. Payroll taxes, Lines 11 through 13, are classified based on Supervised O&M because payroll taxes are a function of labor costs, which is the basis of the Supervised O&M allocator.

Q. HOW ARE OTHER OPERATING REVENUES CLASSIFIED?

A. The classification of other operating revenues is shown on Application Exhibit No. 1, Section 4, Exhibit A, Table 4. Total other operating revenues are an approximately $5.3 million credit that is used to reduce the cost of service to all classes. The other operating revenues and their assignment are as follows:

1. Forfeited Discounts - assigned to Jurisdictional-Direct;
2. Miscellaneous Service Revenues - assigned based on Supervised O&M;
3. Rent from Gas Property - assigned based on Plant in Service; and
4. Other Gas Revenues - assigned based on Supervised O&M.

Q. PLEASE EXPLAIN THE CLASSIFICATION OF THESE REVENUE CREDITS.

A. These other operating revenues are commonly seen revenue credits aligned with the FERC Uniform System of Accounts. Forfeited discounts are assigned to Jurisdictional – Direct and then directly assigned to the Residential customer class since these revenues are primarily associated with past due bills predominantly from Residential customers. Miscellaneous service revenues and other gas revenues are derived from a variety of sources and fees and assigning these revenues based on Supervised O&M spreads the credit out over all the functional services provided. Rent from gas property are assigned based on plant in service because rents are derived from physical facilities and this assignment spreads the credit over all these facilities.

Q. HOW ARE RETURN AND INCOME TAXES CLASSIFIED?

A. These final two items of cost of service are shown in Application Exhibit No. 1, Section 4, Exhibit A, Table 1 and are both classified based on the amount of total rate base assigned to each function.

Q. WHERE IS THE OVERALL FUNCTIONALIZED AND CLASSIFIED COST OF SERVICE SHOWN?

A. All the components of cost of service are summarized in Application Exhibit No. 1, Section 4, Exhibit A, Table 1. The overall cost of service by functional classification shown on Line

11 is then allocated to customer classes in the second step of the CCOSS shown in Application Exhibit No. 1, Section 4, Exhibit B.

B. Cost Allocation

Q. PLEASE DISCUSS THE CONTENTS OF APPLICATION EXHIBIT NO. 1, SECTION 4, EXHIBIT B.

A. Application Exhibit No. 1, Section 4, Exhibit B sets forth the results of my allocation of functionally classified costs developed in Application Exhibit No. 1, Section 4, Exhibit A to customer classes. Application Exhibit No. 1, Section 4, Exhibit B consists of the following schedules:

- Table 1 - Rates of Return Under Current and Proposed Rates;
- Table 2 - Allocation of Cost of Service;
- Table 3 - Allocation of Rate Base;
- Table 4 - Class Allocation Bases; and
- Table 5 - Unit Cost of Service.

Q. HOW DO YOU DEFINE CUSTOMER CLASSES IN THE CCOSS?

A. The customer classes I use in the CCOSS generally align with the customer classes used in the Direct Testimony of Mr. Hyatt's development of billing determinants as discussed in his Direct Testimony. I use the following customer classes in the CCOSS:

- Jurisdictional
  - Residential
  - Commercial
- Non-jurisdictional
  - Agricultural

Maximum Rate

Interruptible

Negotiated – Distribution

Negotiated – Transmission

Negotiated – Direct

Supply - Direct

These customer classes are consistent with the classification of customers discussed in Mr. Hyatt's Direct Testimony and the billing determinants (number of customers and throughput) used in Application Exhibit No. 1, Section 4, Exhibit B to develop the class allocation factors discussed below are developed and discussed by Mr. Hyatt.

Q. PLEASE DISCUSS HOW YOU DEFINED THE JURISDICTIONAL CUSTOMER CLASSES.

A. The Residential customer class includes the current Residential customers from the legacy BH Gas Utility and BH Gas Distribution residential customer classes. The Commercial customer class includes the current commercial and energy options BH Gas Utility customers and the Small and Large Commercial customers from BH Gas Distribution.

Q. PLEASE DISCUSS HOW YOU DEFINED THE NON-JURISDICTIONAL CUSTOMER CLASSES.

A. The Agricultural customer class includes the legacy BH Gas Distribution agricultural customers. The Maximum Rate customer class includes the large volume (i.e. non-jurisdictional) customers that are firm (not interruptible) and whose rates are not individually negotiated. The Interruptible customer class includes large volume customers whose service is non-firm and whose rates are not individually negotiated. The customers

included in the Negotiated-Distribution class are customers whose rates are individually negotiated and are not included in the remaining three non-jurisdictional customer classes. The Negotiated-Transmission customers are those customers, as defined in Exhibit TJS-2, who are directly served off the Company's transmission facilities and are not served from the distribution system. The Negotiated-Direct customers are those customers, as defined in Exhibit No. TJS-2, who are directly served off third-party transmission systems and are not served off either the Company's transmission or distribution system. Finally, the Negotiated-Supply customers include the service associated with customers who provide supply into the Company's system. To the extent that any Negotiated-Supply customer receives gas through Company facilities, these services are provided through facilities separate from the supply function and these services are counted as separate customers under one of the other non-jurisdictional rate classes.

Q. PLEASE DISCUSS APPLICATION EXHIBIT NO. 1, SECTION 4, EXHIBIT B, TABLE 4.

A. Application Exhibit No. 1, Section 4, Exhibit B, Table 4 - Class Allocation Bases, shows the determination of the allocation factors used to allocate the rate base and cost of service that were functionalized and classified in Application Exhibit No. 1, Section 4, Exhibit A to customer classes. Rate Base is allocated to customer classes in Application Exhibit No. 1, Section 4, Exhibit B, Table 3 and cost of service is allocated to customer classes in Application Exhibit No. 1, Section 4, Exhibit B, Table 2.

Q. PLEASE EXPLAIN THE ALLOCATION FACTORS USED TO ALLOCATE TRANSMISSION RELATED COSTS.

A. As previously discussed, transmission related costs are classified as either Transmission – Demand or Transmission – Commodity. The Transmission-Demand related costs are allocated to the jurisdictional and non-jurisdictional customer classes served from the Company's transmission facilities based on the classes' Winter Period Peak Demand. The demand is based on the estimated peak day demand of the customer class as developed in Mr. Hyatt's Exhibit No. DNH-6. The Transmission-Commodity related costs are allocated to the jurisdictional and non-jurisdictional customer classes served from the Company's transmission facilities based on the classes' Annual Throughput (sales plus transportation volumes). The annual throughput is based on the test year adjusted annual volumes as developed in Mr. Hyatt's Application Exhibit No. 1, Section 3, Exhibit A.

No transmission functionalized costs are allocated to the Negotiated-Direct or Negotiated-Supply customer classes because these customers are either directly connected to interstate pipelines or provide supply into the Company's system and all of the Company's pipeline facilities that are required to serve these customers are directly assigned to these customers as discussed in Exhibit No. TJS-2.

Q. PLEASE EXPLAIN THE ALLOCATION FACTORS USED TO ALLOCATE DISTRIBUTION RELATED COSTS.

A. As previously discussed, distribution related costs are classified as either Distribution – Demand, Distribution – Commodity or Distribution - Customer. The Distribution-Demand related costs are allocated to the jurisdictional and non-jurisdictional customer classes served from the Company's distribution facilities based on the classes' Winter Period Peak

Demand. The demand is based on the estimated peak day demand of the customer class as developed in Mr. Hyatt's Exhibit No. DNH-6. The Distribution-Commodity related costs are allocated to the jurisdictional and non-jurisdictional customer classes served from the Company's distribution facilities based on the classes' Annual Throughput (sales plus transportation volumes). The annual throughput is based on the test year adjusted annual volumes as developed in Mr. Hyatt's Application Exhibit No. 1, Section 3, Exhibit A. The Distribution-Customer related costs are allocated to the jurisdictional and non-jurisdictional customer classes served from the Company's distribution facilities based on the classes' number of customers weighted by the distribution customer weighting factors discussed in Exhibit No. TJS-2.

No distributions functionalized costs are allocated to the Negotiated-Direct or Negotiated-Supply customer classes for the same reason that no transmission facilities are allocated to these customer classes. In addition, no distribution functionalized costs are allocated to the Negotiated-Transmission customer class because these customers are served from the Company's transmission facilities and do not utilize distribution facilities.

Q. PLEASE EXPLAIN THE ALLOCATION FACTOR USED TO ALLOCATE SERVICE LINE RELATED COSTS.

A. Service line related costs are allocated to the jurisdictional and non-jurisdictional customer classes based on the classes' number of customers weighted by the service line customer weighting factors discussed in Exhibit No. TJS-2. The weighting factors recognize the relative cost of the service lines (size and length) used to serve each customer class.

Q. PLEASE EXPLAIN THE ALLOCATION FACTOR USED TO ALLOCATE METERS AND REGULATORS RELATED COSTS.

A. Meters and regulators related costs are allocated to the jurisdictional and non-jurisdictional customer classes based on the classes' number of customers weighted by the meters and regulators customer weighting factors discussed in Exhibit No. TJS-2. The weighting factors recognize the relative cost of the meter and regulator installation used to serve each customer class.

Q. PLEASE EXPLAIN THE ALLOCATION FACTOR USED TO ALLOCATE CUSTOMER ACCOUNTING RELATED COSTS.

A. Customer accounting related costs are allocated to the jurisdictional and non-jurisdictional customer classes based on the classes' number of customers weighted by the customer accounting weighting factors discussed in Exhibit No. TJS-2. The weighting factors recognize the relative cost of providing customer accounting related services to each customer class.

Q. PLEASE EXPLAIN THE ALLOCATIONS OF DIRECTLY ASSIGNED COSTS AND OTHER OPERATING REVENUES (REVENUE CREDITS).

A. In the CCOSS, the following costs are directly assigned to customer classes:

1. All plant investment except for meters and regulators associated with service to Negotiated-Direct and Negotiated-Supply customers is directly assigned to the customer class where the customer is assigned. These directly assigned costs are shown on Application Exhibit No. 1, Section 4, Exhibit A, Table 2, Columns N and O, Lines 9 through 21. These directly assigned plant costs also drive the assignment of the other components of the rate base, operation and maintenance expenses,

depreciation expenses, taxes other than income taxes, and other operating revenues (revenue credits) to these customer classes following the same principles used to assign these costs to the other cost functions and classifications that in turn allocate these costs to the other customer classes.

2. Revenues (revenue credit) from forfeited discounts are directly assigned to the Residential customer class because these revenues are primarily derived from that customer class.

Q. PLEASE SUMMARIZE THE ALLOCATION OF RATE BASE IN APPLICATION EXHIBIT NO. 1, SECTION 4, EXHIBIT B, TABLE 3.

A. The classified rate base from Application Exhibit No. 1, Section 4, Exhibit A, Table 1, Line 2, is allocated to the customer classes in Application Exhibit No. 1, Section 4, Exhibit B, Table 3 based on the allocators developed in Application Exhibit No. 1, Section 4, Exhibit B, Table 4, and previously discussed in my testimony, or is directly assigned to a particular class. The direct assignments and allocators used to allocate the various cost of service components are shown in Column H of Table 3 of Application Exhibit No. 1, Section 4, Exhibit B.

Q. PLEASE SUMMARIZE THE ALLOCATION OF THE COST OF SERVICE IN APPLICATION EXHIBIT NO. 1, SECTION 4, EXHIBIT B, TABLE 2.

A. The classified cost of service from Application Exhibit No. 1, Section 4, Exhibit A, Table 1, Line 11, is allocated to the customer classes in Application Exhibit No. 1, Section 4, Exhibit B, Table 2 based on the allocators developed in Application Exhibit No. 1, Section 4, Exhibit B, Table 4 and previously discussed in my testimony, or is directly assigned to a particular class. The direct assignments and allocators used to allocate the various cost of

service components are shown in Column H of Table 2 of Application Exhibit No. 1, Section 4, Exhibit B.

Q. PLEASE DISCUSS APPLICATION EXHIBIT NO. 1, SECTION 4, EXHIBIT B, TABLE 5.

A. Table 5 summarizes the unit cost of service by functional classification for each jurisdictional customer class by dividing the functionalized and classified cost of service by customer class by the applicable billing determinants. These unit costs are used in the next section of my Direct Testimony to develop the cost of service-based rates.

Q. WHAT ARE THE PRINCIPLE FINDINGS OF THE CCOSS?

A. The principle finding is that the jurisdictional rate of return on BH Nebraska Gas utility operations under current rates amounts to 4.56 percent based on a jurisdictional rate base of $503,851.889. The rate of return under current rates indicates that current rate revenues associated with service to BH Nebraska Gas jurisdictional customers are insufficient to cover cost, including an opportunity for BH Nebraska Gas to earn a reasonable return on its investment devoted to public service. In order for BH Nebraska Gas to earn the 7.06 percent jurisdictional rate of return requested in this Rate Review Application, current BH Nebraska Gas rate revenues must be increased by $17.3 million. I summarize rates of return under current rates for the proposed BH Nebraska Gas jurisdictional customer classes in Table TJS-1 below as shown in Application Exhibit No. 1, Section 4, Exhibit B, Table 1, Line 15.

Table TJS-2 - Summary of Rates of Return under Current Rates

Customer Class	Rate of Return
Residential	4.31%
Commercial	5.21%

Q. DOES THIS CONCLUDE YOUR TESTIMONY REGARDING YOUR CCOSS?

A. Yes, it does.

IV. BACKGROUND RATE DESIGN DISCUSSION

Q. PLEASE SUMMARIZE WHAT YOU WILL DISCUSS IN THIS SECTION OF YOUR DIRECT TESTIMONY.

A. I will first discuss the history of the BH Gas Distribution jurisdictional rate design up to the current jurisdictional residential and commercial rates on the BH Nebraska Gas system. Then, I will discuss the history of the BH Gas Utility jurisdictional rate design up to the current jurisdictional residential and commercial rates on the BH Nebraska Gas system.

Q. PLEASE DISCUSS THE BH GAS DISTRIBUTION JURISDICTIONAL RATE DESIGN PRIOR TO THE ESTABLISHMENT OF THE COMMISSION.

A. Prior to regulation by the Commission, jurisdictional rates in Nebraska were regulated by the local municipalities. As discussed earlier in my direct testimony, prior to FERC Order No. 636, the BH Gas Distribution System (then known as KN Energy and then Kinder Morgan), was a vertically integrated gas company. At that time, rates in Nebraska were governed by what was referred to as the "used and useful" method. In addition, rates were also established regionally around "target towns".

Q. PLEASE EXPLAIN WHAT IS MEANT BY THE USED AND USEFUL METHOD AS IT PERTAINED TO THE ESTABLISHMENT OF RATES FOR BH GAS DISTRIBUTION IN NEBRASKA PRIOR TO THE ESTABLISHMENT OF THE COMMISSION.

A. Under the used and useful methodology, a town on the system would be allocated only the cost of facilities that were used and useful to providing service to that town. These facilities included production, gathering, storage, transmission, and distribution. In other

words, only the facilities upstream of the town that were used to deliver gas from the source of supply were deemed used and useful. At that time, the BH Gas Distribution system was generally supplied gas from Wyoming and Southwest Kansas and an interconnection with Northern Natural Gas in Southeast Nebraska. Under the used and useful method, a town would be allocated its allocated share of facilities that were used to deliver gas to that town based on which combination of these supplies flowed to that town. Thus, in Nebraska, there was virtually a matrix of facilities that served different groups of customers depending upon where they were located on the system. Generally, prior to FERC Order No. 636 and the separation of upstream services, towns in the Northeast part of the system had the highest rates because they utilized all the facilities. Towns in the Northwest part of the system had the lowest rates because they used only the facilities to the west into Wyoming. Towns were directly assigned the cost of their distribution systems.

Q. PLEASE EXPLAIN WHAT IS MEANT BY TARGET TOWNS AS IT PERTAINED TO THE ESTABLISHMENT OF RATES FOR BH GAS DISTRIBUTION IN NEBRASKA PRIOR TO THE ESTABLISHMENT OF THE COMMISSION.

A. Under the municipal regulation model, each town could request a specific rate study for its location based on the used and useful allocation method. Due to the fact that the BH Gas Distribution system served well over 100 towns and many of these town were very small, the towns with few exceptions accepted studies done for target towns in their particular region because the cost of doing studies for each town would be high and the cost for a small town would be very expensive on a per customer basis. For example, the towns in

the vicinity of McCook that generally used the same upstream facilities as McCook would accept the rate approved for a study of the cost of service for McCook. Under the BH Gas Distribution system, the number of target towns was around a dozen. The target town concept evolved into what was referred to as rate areas at the time of the initiation of Commission regulation.

Q. PLEASE GENERALLY EXPLAIN THE JURISDICTIONAL RATE STRUCTURES ON THE BH GAS DISTRIBUTION SYSTEM USED PRIOR TO COMMISSION REGULATION.

A. Prior to Commission regulation, the BH Gas Distribution system "jurisdictional" rate consisted of separate rates by rate area (target towns) for Residential and Commercial service. The rates consisted of a flat monthly customer charge and volumetric rates with multiple blocks. As will be discussed below, after Commission regulation the multiple block structure was simplified to the current rate structures containing two blocks and the multiple rate areas were consolidated into system-wide residential and commercial rates.

Q. PLEASE GENERALLY EXPLAIN THE CHANGES THAT OCCURRED TO JURISDICTIONAL RATE STRUCTURES ON THE BH GAS DISTRIBUTION SYSTEM AFTER FERC ORDER NO. 636.

A. As previously discussed, the vertically integrated system of Kinder Morgan (BH Gas Distribution) was broken up as a result of FERC Order No. 636 to separate the distribution service from the upstream services. At that time, the rates of BH Gas Distribution were

adjusted to remove those upstream costs that were then to be reflected in the cost of gas transportation that would be included in the cost of purchased gas. The rate structures and rate areas did not change but the rates were lowered to remove the upstream costs. The removal of these upstream costs tended to jumble the historical differential between the rate areas as will be discussed later in my testimony. This occurred prior to Commission regulation.

Q. PLEASE GENERALLY EXPLAIN HOW NON-JURISDICTIONAL RATES WERE ESTABLISHED ON THE BH GAS DISTRIBUTION SYSTEM PRIOR TO COMMISSION REGULATION.

A. Prior to the establishment of the Commission, non-jurisdictional rates were developed essentially in the same manner as they are today. The non-jurisdictional customer rates were not regulated by the local municipalities but were either established through specific studies for those customers and/or by negotiation. Rural residential and commercial customers who were outside the city limits of the municipalities paid the same rates as those in the nearest town.

Q. WHEN WAS THE FIRST GENERAL RATE REVIEW FOR SOURCEGAS UNDER THE COMMISSION?

A. It was Kinder Morgan's rate review Commission Application No. NG-0036 based on a test year ended December 31, 2005. Among other issues, Mr. William Meckling and I co-sponsored the rate design proposed by the Company in that matter.

Q. PLEASE GENERALLY DISCUSS THE EXISTING RATES AT THE TIME OF THAT FILING.

A. As discussed earlier, the existing rate structure and rates were a carryover from the era of local municipal regulation and the historical differentials were somewhat jumbled due to the removal of upstream costs. There were 11 different rate areas with 12 different rates for Residential and Commercial service. Generally, both sets of rates had four volumetric blocks, different usage levels between the Residential and Commercial blocks, and a customer charge. The customer charges were very low (as low as $3 per month for Residential customers in some rate areas) and were not uniform across the various rate areas, likely due to differences in timing when the rates were last changed under local municipal regulation, and there was variation between the volumetric rates for each of the blocks, partially due to the effect of unbundling the upstream facilities and the timing of past rate changes.

Q. PLEASE DISCUSS THE KINDER MORGAN (BH GAS DISTRIBUTION) RATE DESIGN PROPOSAL IN COMMISSION APPLICATION NO. NG-0036.

A. As discussed in my direct testimony in that case, BH Gas Distribution's proposed rates were based on the following:

1. Uniform Residential and uniform Commercial rates across the whole system, i.e. all rate areas.

2. Increased customer charges to be better aligned with customer related costs.

3. Simplified existing four block volumetric rate structures into two blocks as follows:

   a. Residential - First 20 therms and over 20 therms

   b. Commercial – First 80 therms and over 80 therms.

   These blocks were based on analyses similar to that discussed in Mr. Hyatt's direct testimony in the current case.

4. Retained existing differentials between Residential and Commercial rates. These differentials were comparable to the rate structures reflected by the competing electric companies.

5. Priced the second usage blocks as low as practical. This is consistent with both the rate structures of competing electric companies and the pricing in the last block of the then current four block rate structures.

In my testimony in Commission Application No. NG-0036, I discussed the rate structures of the municipal electric utilities with which Kinder Morgan competed and how those rate structures and other incentives were used to encourage customers to not only use electric appliances rather than natural gas but to encourage customers to replace natural gas appliances with electric appliances (primarily space heating equipment). In my testimony, I showed that Kinder Morgan was experiencing significant loss in customers and lost load due to this competition. The pricing of the second block of the proposed Residential and Commercial rates was explicitly done to address this competition. Kinder Morgan also

proposed a High Efficiency Appliance Tool program (HEAT) to address similar programs offered by the municipal electric utilities.

Q. WHAT RATES DID THE COMMISSION APPROVE FOR KINDER MORGAN (BH GAS DISTRIBUTION) IN COMMISSION APPLICATION NO. NG-0036.

A. In Commission Application No. NG-0036, the Commission in its Order Approving Stipulation approved the following:

1. Merging the existing 11 rate areas into one rate area for the entire state (same as what was proposed in Item 1 in the prior answer).
2. A Residential rate with the same block structure in Item 3 in the prior answer with a significantly lower second block (as proposed in Item 5 in the prior answer).
3. A phase-in with increasing customer charges over a three-year period with reductions in the second block offsetting the revenue increase from the higher customer charges. The first block rates set initially were not changed during the subsequent 2-year phase-ins.
4. Splitting the Commercial rate into Small and Large Commercial classes. The Large Commercial class was created with the same block structure as proposed in Item 3 in the prior answer and the Small Commercial class was created with blocks of first 40 therms and over 40 therms.
5. At the end of the 3-year phase-in the volumetric block rates were the same for all three rates (but with different therm levels for each block as discussed above). The

first volumetric block for all three rates was $0.3500 per therm and the second block $0.1086 per therm.

6. Accepted the HEAT program.

Q. WAS THIS RATE STRUCTURE CHANGED IN SOURCEGAS' NEXT RATE REVIEW IN COMMISSION APPLICATION NO. NG-0060?

A. No. The SourceGas proposed and the Commission approved (in its Order Granting Application in Part dated March 9, 2010) the same rate structure that resulted from Commission Application No. NG-0036. The Commission retained "the status quo with respect to the relationship between the various classes and ratepayers and between the volumetric and fixed charges." Generally, the rates approved in NG-0060 were proportionately higher than those approved in NG-0036 with the exception that a larger percentage increase was applied to the Large Commercial customer charge. The resulting volumetric block rates approved in NG-0060 were $0.4220 per therm for the first blocks and $0.1208 for the second blocks. The HEAT program was also approved with the addition of water heaters to the program.

Q. DID YOU PROVIDE SIMILAR TESTIMONY IN COMMISSION APPLICATION NO. NG-0060 AS YOU DID IN NG-0036 REGARDING CUSTOMER TRENDS AND COMPETITION?

A. Yes. On Page 9 of my direct testimony in Commission Application No. NG-0060 I discussed the trend in lost customers but also state: "the rate structure and HEAT program

that were approved in Kinder Morgan's 2006 rate case have helped to mitigate this trend significantly." In response to the continuing decline I sponsored a pro forma adjustment to reflect lost customers and a rate rider to capture future changes in the number of customers served. As stated in the Commission's Order Approving Recalculated Rates and Refund Plan, the Commission approved the billing determinants as adjusted by the Company including the pro forma adjustment for lost customers. However, as stated in the Commission's Order Granting Application in Part, the rate rider was not approved.

Q. PLEASE DISCUSS YOUR TESTIMONY IN SOURCEGAS' NEXT RATE CASE AFTER COMMISSION APPLICATION NO. NG-0060.

A. SourceGas' next rate review was Commission Application No. NG-0067. Similar to Commission Application No. NG-0060, I sponsored SourceGas' proposed rate design including lost customer and use per customer riders, and the Company also proposed pro forma adjustments to reflect declining number of customers and declining use per customer. Regarding the Company's proposed rate design, I recommended maintaining the existing block rate structures with increases to customer charges and equal percentage increases to both tiers (blocks).

Q. DID YOU PROVIDE SIMILAR TESTIMONY IN COMMISSION APPLICATION NO. NG-0067 AS YOU DID IN NG-0036 and NG-0060 REGARDING CUSTOMER TRENDS AND COMPETITION?

A. Yes. In my direct and rebuttal testimonies, I provided similar testimony regarding the decline in customers and competition from municipal electric systems. In my rebuttal testimony (Page 15) I stated: "The primary reason for SourceGas Distribution's customer decline is customers switching from natural gas space heating to electric space heating." I attributed this switching to both the rate design of the municipal electric utilities and the rebates.

Q. WHAT RATES DID THE COMMISSION APPROVE FOR SOURCEGAS IN COMMISSION APPLICATION NO. NG-0067?

A. The rates resulting from the Commission's Order Granting Application in Part in Commission Application No. NG-0067 maintained the existing block structures and relative rates for the volumetric blocks. Customer charges were increased for all classes. The resulting volumetric block rates (for all jurisdictional rates) approved in NG-0067 were $0.4675 per therm for the first blocks and $0.1338 for the second blocks. Consistent with the recommendation in my direct testimony, the two blocks were increased by the same percentage. The HEAT program was also approved with some additional provisions. The Commission explicitly recognized the issues related to customer loss when it stated with regard to the HEAT program that "a rebate program to assist the Company in retaining

customers is important in light of evidence regarding customer loss in SourceGas' service area." The Commission did not approve the customer loss and use per customer riders proposed by the Company.

Q. PLEASE DISCUSS THE BH GAS UTILITY JURISDICTIONAL RATE DESIGN PRIOR TO THE ESTABLISHMENT OF THE COMMISSION.

A. I did not work on the BH Gas Utility rate reviews in Nebraska prior to the establishment of the Commission. However, I did sponsor the weather normalization adjustments in Aquila's first rate review before the Commission in Application Nos. NG-0001, 0002, and 0003. Thus, I am familiar with the rate structures that existed at that time which would be the rate structures prior to the Commission's establishment. The BH Gas Utility system had three jurisdictional rate areas that generally followed the two systems that formed Aquila's system in Nebraska. The first system was the original Northern Natural Gas distribution system (called Peoples Natural Gas) that served Lincoln and the areas around Omaha; these two areas constituted Rate Areas 1 and 2, respectively. The second system was the original Minnegasco system that was acquired by Aquila that serves the areas North of Omaha around Norfolk. This was the Aquila Rate Area 3. Jurisdictional customers in these three rate areas were served under three separate Residential and Commercial rates that contained a customer charge and a flat volumetric charge. These separate rate areas were retained after this first set of rate reviews because these rate structures existed at the time

Aquila filed its next rate review in Commission Application No. NG-0041 when I did sponsor the Company's CCOSS and rate design.

Q. PLEASE DISCUSS BH GAS UTILITY'S JURISDICTIONAL RATE DESIGN PROPOSED IN COMMISSION APPLICATION NO. NG-0041.

A. In Commission Application No. NG-0041, I sponsored the BH Gas Utility's rate design which reflected the consolidation of the three rate areas into one consolidated residential rate and one commercial/energy options rate. The Residential and Commercial rates had different customer and volumetric charges based on the results of the CCOSS that I also sponsored. I also presented two alternate rate design options. Under one alternate option all of the proposed revenue increase was reflected in the proposed customer charge with the volumetric charges being consolidated for the three areas but the amount of revenue collected through the volumetric charges being unchanged. Under a second alternate option, the volumetric rates were eliminated and all of the revenue requirement collected through a customer charge. This second alternative is more commonly referred to as a straight fixed variable ("SFV") rate design.

Q. WHAT RATES DID THE COMMISSION APPROVE FOR AQUILA IN COMMISSION APPLICATION NO. NG-0041.

A. In its Order Granting Application in Part in Commission Application No. NG-0041, the Commission approved the consolidation of the separate rate area rates into statewide rates. The Commission approved the more traditional rate design similar to what I recommended and thus did not approve either of the optional alternatives I presented. Thus, the rates approved by the Commission in Commission Application No. NG-0041 for the Residential and Commercial classes included an increase from the average of the existing customer charges and an increase to the flat volumetric rate relative to the average of the existing volumetric rates. The Commission also indicated that "the Commission will continue to be open to innovations in rate design that will be in the best interest of ratepayers."

Q. PLEASE DISCUSS THE BH GAS UTILITY JURISDICTIONAL RATE DESIGN PROPOSED IN COMMISSION APPLICATION NO. NG-0061.

A. I sponsored BH Gas Utility's proposed rate design in Commission Application No. NG-0061 and that proposed rate design reflected the following:

1. A further consolidation of the jurisdictional rate design with different customer charges for Residential and Commercial service but with the same volumetric rates.
2. A declining block rate similar to the structure the Commission had previously approved for SourceGas.
    a. Residential - First 20 therms and over 20 therms.

b. Commercial – First 40 therms and over 40 therms.

Q. WHY DID YOU PROPOSE THE IMPLEMENTATION OF THE BLOCK RATE STRUCTURE FOR BH GAS UTILITY IN COMMISSION APPLICATION NO. NG-0061?

A. As discussed in my direct testimony, there were two reasons. First, the first block can be designed to recognize that the customer charge does not recover all the fixed costs of service. Second, the second block can be designed to more effectively compete with the rate structures of the municipal electric systems that target heat-sensitive usage. I also stated in my direct testimony that the other two gas systems regulated by the Commission, SourceGas and Northwestern, both had declining block rate structures.

Q. DID YOU PROVIDE TESTIMONY IN COMMISSION APPLICATION NO. NG-0061 REGARDING THE COMPETITIVE THREATS FACED BY BH GAS UTILITY?

A. Yes. I provided testimony regarding the three largest municipal electric systems in Nebraska, Omaha Public Power District, Nebraska Public Power District, and Lincoln Electric Service, in addition to two other smaller municipal electric systems in BH Gas Utility's service territory. All three of the large municipal electric systems had electric rate structures that had significantly lower winter blocks explicitly designed to attract electric space heating load. As discussed in my direct testimony, the rates I proposed for BH Gas

Utility in Commission Application No. NG-0061 were specifically designed to better compete with these three electric systems.

Q. WHAT RATES DID THE COMMISSION APPROVE FOR AQUILA IN COMMISSION APPLICATION NO. NG-0061.

A. In its Final Order Granting Application in Part in Commission Application No. NG-0061, the Commission maintained the existing rate structure with one exception. The Commission established a higher volumetric rate for the Residential rate than the Commercial rate due to its gradual approach in raising customer charges and to avoid the Commercial class subsidizing the Residential class.

V. COMPETITIVE ISSUES

Q. PLEASE OUTLINE THE ISSUES YOU ADDRESS IN YOUR DIRECT TESTIMONY REGARDING COMPETITIVE ISSUES.

A. Similar to testimony I have provided in past rate cases for BH Gas Distribution and BH Gas Utility, I will discuss trends in numbers of customers, primarily focusing on the BH Gas Distribution system. Second, I will discuss the specific rates offered by the municipal electric utilities that provide service in the same areas as both the BH Gas Distribution and BH Gas Utility systems focusing on the rate design of these electric utilities and specifically on how their rates are designed to target winter heating load with which the Company directly competes.

Q. WHAT HAS BEEN THE COMPANY'S EXPERIENCE WITH REGARDS TO THE NUMBER OF CUSTOMERS IT SERVES IN THE FORMER BH GAS DISTRIBUTION SYSTEM IN NEBRASKA?

A. In the last SourceGas rate review in Commission Application No. NG-0067, I sponsored an exhibit showing the annual average number of customers for the period 2000-2011 (annual periods ending March 31). I have included that exhibit as Exhibit No. TJS-3 attached to my direct testimony in this case[4]. In Commission Application No. NG-0067, I made the following observations regarding the customer trends SourceGas was experiencing: "Over the twelve-year period 2000-2011, the Company has incurred a net loss of 12,047 Residential customers, 1,411 Small Commercial customers, and 211 Large Commercial customers."

In his direct testimony supporting his recommended customer growth adjustment, Mr. Hyatt is sponsoring a similar exhibit (DNH-4) using data for the period 2010 through 2019 (annual periods ended December 31). The total number of Residential and Commercial customers in Exhibit No. TJS-3 for 2011 of 79,549 (12 months ended March 31, 2011) compared to 79,688 for 2010 (December 31) and 79,245 for 2011 (December 31) verifies that these two analyses are comparing the same figures but over slightly varied fiscal periods. As shown in Exhibit No. DNH-4, the total number of Residential and Commercial customers for the former BH Gas Distribution service area is

[4] Exhibit TJS-3 in this Rate Review Proceeding was marked as Testimony Exhibit TJS-4 in Commission Application No. NG-0067.

79,836 which is 287 customers higher than the number of customers at the time of the last SourceGas rate review.

Q. WHAT DOES THE COMPARISON OF THE SITUATION AT THE TIME OF SOURCEGAS' LAST RATE REVIEW AND THE CURRENT RATE REVIEW DEMONSTRATE TO YOU?

A. It demonstrates that the significant decline in residential and commercial customers improved substantially almost immediately after the last SourceGas rate review.

Q. TO WHAT DO YOU ATTRIBUTE THIS SUBSTANTIAL IMPROVEMENT?

A. I attribute a significant factor in this improvement to the Commission's approval of both SourceGas' proposed block rate structure and the HEAT program. As discussed earlier in my testimony, the Commission first approved the block rates and HEAT program in Commission Application No. NG-0036 and approved them both in the subsequent SourceGas rate reviews in Commission Application Nos. NG-0060 and NG-0067. I believe that the Commission's granting and reaffirming of the existing BH Gas Distribution block rate structure was an important response to addressing the competitive issues faced by SourceGas and has proved successful in stemming what had been a long-term customer decline on the BH Gas Distribution system. As will be discussed later in my direct testimony, I am recommending that the existing BH Gas Distribution rate structure be retained and used as the basis for the consolidated statewide rate proposed by the Company in this case.

Q. PLEASE EXPLAIN THE NATURE OF THE COMPETITION THE COMPANY IS FACING FROM ELECTRIC UTILITIES.

A. The Company faces competition in the form of prices, cash incentives (rebates), and advertising. Electric utilities in Nebraska are using all three means to attract traditional natural gas space heating, water heating, and other loads (cooking and clothes drying) from Residential and Commercial customers.

Q. WHAT HAVE BEEN THE PRIMARY INCENTIVES FOR NATURAL GAS HEATING CUSTOMERS TO SWITCH FROM NATURAL GAS TO ELECTRICITY?

A. There are two primary interrelated incentives offered by the local electric utilities to encourage customers to switch from natural gas to electricity, or to use all-electric appliances in new construction. The first incentive is rebates, as discussed in the testimony of Dr. David Rosenbaum. Rebates reduce the upfront cost of changing from natural gas appliances to electric appliances, and reduce the cost of the initial installation of appliances. The second incentive is a rate design used by the electric utilities that specifically targets reducing the energy cost of operating space and water heating equipment. In my testimony, I will focus on how residential and commercial electric rates are being designed to primarily promote electric space heating and secondarily electric water heating.

Q. WHICH ELECTRIC UTILITIES DOES THE COMPANY COMPETE WITH IN NEBRASKA?

A. The electric utility industry in Nebraska is comprised of numerous publicly owned electric utilities. However, the prices generally offered to residential and commercial customers are very similar in structure. In Exhibit No. TJS-4, I summarize the Residential and

Commercial rates offered by the 10 electric utilities who serve most of the Company's natural gas customers. The three largest of these electric utilities are Lincoln Electric System ("LES"), Nebraska Public Power District ("NPPD"), and Omaha Public Power District ("OPPD"). These three systems serve over 70 percent of the Company's customers. The next 7 serve approximately 10 percent; and the numerous other small electric systems serve the remaining 20 percent. A cursory examination of the rates summarized in Exhibit No. TJS-4 reveals how similar they are in structure and pricing. I will focus on characteristics specific to the three largest electric utilities, LES, NPPD, and OPPD. I have provided copies of their current residential and commercial electric rate schedules in Exhibit No. TJS-5.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING LES' PRICING STRUCTURE?

A. Yes, I do. My observations include:

1. The customer charges for service to Residential customers are tiered based on the size of the customer and range from $23.10 per month to $50.00 per month.
2. The customer charges for service to Commercial (General Service) customers are tiered based on the size of the customer and range from $23.00 per month to $58.00 per month.
3. LES also offers a Heating Service rate for non-residential (i.e. Commercial) customers who use electricity for space heating and/or water heating. The customer charges for Heating Service customers are tiered based on the size of the customer and range from $37.75 per month to $275 per month.

4. LES prices residential service at a flat rate of 8.01 cents per kilowatt-hour during the summer and at a flat rate during the winter of 5.48 cents per kWh.

5. LES prices small commercial service (secondary) at a flat rate of 9.08 cents per kWh during the summer and at a flat rate of 6.06 cents per kWh during the winter. Larger commercial customers (primary) are similarly priced at 8.80 cents per kWh during the summer and 5.85 cents per kWh during the winter.

6. For its Heating Service, LES prices small commercial service at a flat rate of 8.05 cents per kWh during the summer and at a flat rate of 4.93 cents per kWh during the winter. Larger commercial customers are priced at 7.76 cents per kWh during the summer and 4.80 cents per kWh during the winter.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING NPPD'S PRICING STRUCTURE?

A. Yes, I do. My observations include:

1. The customer charge for service to Residential customers is $22.50 per month.

2. The customer charge for service to small Commercial (Single-phase General Service) customers is $32.50 per month. The customer charge for larger Commercial (Three-phase General Service) is $48.50 per month.

3. Like LES, NPPD also offers an electric space heating service for Commercial customers. The customer charges for small commercial and larger commercial customers are $54.00 per month and $72.50 per month, respectively.

4. NPPD prices residential service under two blocks and charges seasonally differentiated prices. NPPD sets the second block for service in the winter at 6.22 cents per kWh which is below the other energy charges for non-heating winter

load and summer usage which are 8.08 cents per kWh and 10.13 cents per kWh, respectively.

5. NPPD prices commercial service at a flat rate of 9.73 cents per kWh during the summer and at flat rate of 7.33 cents per kWh during the winter.

6. NPPD prices its Commercial space heating rate under two blocks (using an hour's use formula) and charges seasonally differentiated prices. The second block during the winter is 3.72 cents per kWh and during the summer at 4.77 cents per kWh, both substantially lower than the first blocks of 9.16 cents per kWh during the winter and 12.74 cents per kWh during the summer.

Q. DO YOU HAVE ANY OBSERVATIONS WITH REGARDS TO OPPD'S PRICING STRUCTURE?

A. Yes, I do. My observations include:

1. The customer charge for service to Residential customers is $30 per month, but there is also a minimum bill of $32.07 per month.

2. The customer charges for service to Commercial (General Service) customers is $33 per month.

3. OPPD has a targeted rate similar to NPPD and LES, except that it targets residential customers with high-efficiency heat pumps. The rate is called Residential Conservation Service. The customer charges and minimum bill for this service are the same as the regular residential rate.

4. OPPD prices residential service a flat rate of 9.36 cents per kilowatt-hour during the Summer and under a three-block declining rate during the winter with the last block at 5.27 cents per kWh.

5. OPPD's block structure for commercial service is similar to the structure it offers for residential service but with slightly lower rates and two blocks during both the summer and winter. The second winter block is priced at 5.24 cents per kWh.

6. OPPD prices the Residential Conservation (high efficiency heat pump) service at the same rate as Residential service during the summer, but with a lower last winter block of 4.31 cents per kWh.

Q. WHAT ARE THE COMMON THREADS IN ALL THREE OF THESE SETS OF RATES?

A. The following are three common threads in their rates:

1. All three utilities price winter service substantially below summer service.

2. All three utilities have customer charges that are significantly higher than Black Hills Nebraska Gas' residential customer charges.

3. All three utilities have special rates that specifically target space or water heating.

Q. PLEASE DISCUSS IN MORE DETAIL THE ELECTRIC UTILITY WINTER PRICING IN THEIR RESIDENTIAL RATES.

A. The table below compares the summer consumption rates and winter rates of LES, NPPD, and OPPD. The winter rate shown is for the last block which is designed to incrementally reflect heat usage above typical average usage excluding heat load.

Table TJS-3 - Comparison of Winter and Summer Residential Electric Rates

Utility	Summer Cents/kWh	Winter Cents/kWh	Difference
LES	8.01	5.48	-32%
NPPD	10.13	6.22	-39%
OPPD	9.36	5.27	-44%
OPPD-Res. Conservation	9.36	4.31	-54%

The comparison for LES, NPPD, and OPPD's commercial rates is similar.

Q. PLEASE DISCUSS IN MORE DETAIL THE ELECTRIC UTILITY CUSTOMER AND FIXED CHARGES IN THEIR RESIDENTIAL RATES.

A. The table below compares the customer and fixed charges in the electric rates of LES, NPPD, and OPPD. LES' fixed per bill charges include a customer charge and a facilities charge; the facilities charge is tiered based on the size of the customer. NPPD's fixed charge is referred to as a customer charge. OPPD's fixed charge is referred to as a service charge. Also, shown in the table is the level of these fixed charges at the time of the Company's last rate cases. The customer charge for NPPD is taken from my Exhibit No. TJS-12 in Commission Application No. NG-0067 (the last BH Gas Distribution rate case) and the customer charges for OPPD and LES are taken form my Exhibit No. TJS-8 in Commission Application No. NG-0061 (the last BH Gas Utility rate case).

Table TJS-4 - Comparison of Residential Electric Utility Customer and Other Fixed Charges

Utility	Current Customer Charge $/bill	Last BH Rate Cases Customer Charge $/bill
LES	23.00 to 50.00	8.95
NPPD	22.50	18.00
OPPD	30.00	8.05

As shown in the table above, the electric utilities have substantially increased the fixed price component of their residential rates. As with natural gas rates, to the extent that fixed or customer charges are increased, less margin revenue needs to be recovered from the variable components of the rates. Thus, by substantially increasing their customer charges, the electric utilities are collecting more of the revenue requirement through the fixed charges and proportionately less through their volumetric charges.

The commercial and general service rates of these electric utilities have seen similar substantial increases since the Company's most recent rate cases.

Q. PLEASE DISCUSS IN MORE DETAIL THE SPECIAL TARGETED RATES OFFERED BY THE ELECTRIC UTILITIES.

A. All three of the electric utilities, LES, NPPD, and OPPD, offer rates that are intended to target specific end-use customers who might otherwise use natural gas for their appliances or equipment. As discussed earlier regarding Exhibit No. TJS-4, LES offers a Heating Service for non-residential (i.e. commercial) customers that is available to "any non-residential customer for space heating and/or approved water heating installations". This Heating Service Rate is priced not only substantially below the summer rate but also

substantially below the standard winter rate offered to General Service (commercial) customers. Depending upon the size of the customer the winter rate for the Heating Service rate is 4.93 cents per kWh or 4.80 cents per kWh compared to a summer rate of 8.05 cents per kWh or 7.76 cents per kWh; and also compares to a winter rate for the General Service rate of 5.85 cents per kWh or 6.06 cents per kWh.

NPPD offers a similar rate targeted to commercial customers called Commercial Electric Space Heating. This rate is offered to customers where "electricity is the primary (greater than 50 percent) source of energy for space heating". The winter last block rate for the Commercial Space Heating rate is 3.72 cents per kWh compared to the standard General Service winter rate of 7.33 cents per kWh. The summer first block rate for the Commercial Space Heating rate is 12.74 cents per kWh.

OPPD offers a Residential Conservation Service rate available to residential customers who "have an electric heat pump in operation that has a Seasonal Efficiency Rating of 14 or higher…and supply at least 50 percent of space conditioning requirements using the electric heat pump." The winter last block rate for this Residential Conservation Service is 4.31 cents per kWh compared to 5.27 cents per kWh for the standard Residential winter rate and 9.36 cents per kWh for the summer rate (same as standard Residential rate).

Q. WHAT IS THE COMMON THEME IN ALL OF THE SPECIFIC RATES YOU HAVE DISCUSSED?

A. In all cases, the lower winter block rates and higher customer charges allow the electric utilities to lower the incremental cost to the customers of operating electric heating equipment.

Q. PLEASE EXPLAIN WHY THE LAST WINTER BLOCK OF ELECTRIC RATE PRICING IS CRITICAL TO SPACE HEATING.

A. In the typical Nebraska electric utility residential block rate design, the blocks are set such that the normal or base use is priced in the first block and then incremental use above this level, for seasonal space heating, for example, is priced at a lower price. The base use includes electricity used for such things as lighting, computers, televisions, refrigerators, freezers, etc. that are used all year long and do not have a significant seasonal pattern. Natural gas does not compete with these loads that almost exclusively run on electricity.

LES does not have block rates for its residential services, but as discussed earlier, their winter rates are substantially below their summer rates and this winter rate is what primarily competes with natural gas space heating. The last winter block of NPPD's rate is based on usage over 750 kilowatt-hours. Residential customers who are or were using natural gas space heating are likely not using more than 750 kilowatt-hours of electricity in the winter months. Therefore, the 750-kilowatt-hour block applies to electric customers who use some form of electric space heating. In other words, this block is specifically targeted at electric space heating. Similarly, OPPD's last winter block is for usage over 880 kilowatt-hours.

The fact that LES, NPPD, and OPPD (and the other electric utilities shown in Exhibit No. TJS-4) are heavily discounting either their winter residential rate or the last block of their winter rate is strong evidence that these utilities are leveraging this rate to attract electric space heating load. Since the customers are already electric customers, most of the additional winter usage (that would result from switching from natural gas to electric space heating) would be priced at these discounted rates.

Q. UP TO THIS POINT YOU HAVE DISCUSSED THE SPECIFICS OF THE THREE LARGEST ELECTRIC UTILITIES IN NEBRASKA. ARE THE RATE STRUCTURES FOR THE SMALLER ELECTRIC UTILITIES SIMILAR?

A. Yes. As shown in Exhibit No. TJS-4, these electric utility pricing structures are almost universal in the state of Nebraska. The only utility in Exhibit No. TJS-4 that does not differentiate summer and winter rates is the City of Columbus. Further, the only utilities in Exhibit No. TJS-4 that have relatively lower residential customer charges are the City of Columbus and the City of Beatrice. All the others have pricing structures similar to NPPD and OPPD.

Q. ARE THERE ANY OTHER RATES YOU WOULD LIKE TO DISCUSS FOR COMPARISON PURPOSES?

A. Yes. The current rates of Northwest Public Service (NPS), the other investor-owned natural gas utility in Nebraska, have rate structures and rates for residential and commercial service that are very similar to the existing BH Gas Distribution rates and rate structures. I have provided copies of the current NPS residential and commercial rates for comparison in Exhibit No. TJS-6. NPS' residential rate has two blocks with the second block priced approximately 62 percent lower than the first block and the general service (commercial) rate has three blocks with the second block priced 52 percent lower than the first block and the third block at 72 percent less than the first block.

Q. IN YOUR OPINION, HOW SHOULD THE COMPANY'S RATES BE STRUCTURED AND WHY?

A. It is my opinion that the Company's current rate structure on BH Gas Distribution should be used for the system-wide rates, specifically, the block rate structure used for BH Gas

Distribution's current rates. The current BH Gas Distribution rate structure is comparable to the electric rate structures in Nebraska that I discussed above. Rates are one of several tools used by the electric utilities that provide service in the Company's territory to directly compete with the Company. Implementing block rates on the entire BH Nebraska Gas system will provide the Company with one of these tools that can be used to improve their competitive position.

VI. PROPOSED JURISDICTIONAL RATE DESIGN

Q. WHAT GUIDELINES DID YOU FOLLOW IN THE DESIGN OF PROPOSED RESIDENTIAL AND COMMERCIAL RATES?

A. The guidelines I used to design the proposed Residential and Commercial rates (i.e. the jurisdictional rates) are as follows:

1. The overall increase in jurisdictional rates should total approximately $17.3 million.
2. The separate jurisdictional rates currently in place for BH Gas Distribution and BH Gas Utility should be consolidated into one set of system-wide rates as discussed in Mr. Amdor's direct testimony.
3. The rates should be designed as close as practical to align with each classes' cost of service.
4. Rates should be designed to reflect the competition faced by the Company from local municipal electric utilities.
5. The customer charges should move in the direction of reflecting customer related costs.

6. In order to mitigate the impact of moving the BH Gas Utility customers from a flat volumetric rate to block rates, a relatively smaller increase in the residential customer charge should be implemented.

7. To the extent practical, the existing differentials between the residential and commercial rates and between the block rates should be maintained.

In this section of my direct testimony, I first discuss purely cost-based jurisdictional rates and then I present and discuss the rates I am recommending and the jurisdictional rates being proposed by BH Nebraska Gas. Finally, I discuss a flat volumetric rate alternative should the Commission determine that it would rather implement a flat volumetric charge than the block rate structure the Company is proposing that is currently used in the BH Gas Distribution system.

Q. AS DISCUSSED EARLIER IN YOUR TESTIMONY, THE CURRENT JURISDICTIONAL RATE STRUCTURES OF THE FORMER BH GAS DISTRIBUTION AND BH GAS UTILITY SYSTEMS ARE DIFFERENT. WHAT RATE STRUCTURES ARE YOU RECOMMENDING FOR THE CONSOLIDATED SYSTEM?

A. I am recommending that the jurisdictional rates implemented for the consolidated system incorporate aspects of both rate structures. I am recommending that the existing BH Gas Utility structure including Residential and Commercial rates be applied statewide. Thus, the existing Large Commercial customers on the BH Gas Distribution system will be combined into one set of Commercial rates for the whole state. Secondly, I am

recommending that the existing block rate structure on the current BH Gas Distribution system for Residential and Commercial rates be implemented for the whole state.

Q. WHY DO YOU BELIEVE IT IS PREFERABLE TO IMPLEMENT THE EXISTING BH GAS UTILITY CLASS STRUCTURE FOR JURISDICTIONAL RATES?

A. Primarily, I am recommending one commercial rate to reduce the impact on the BH Gas Utility larger commercial customers of implementing significantly higher customer charges than they have paid in the past if they were moved to a Large Commercial rate. Secondarily, combining the two BH Gas Distribution commercial rates will eliminate the need to continually monitor customers near the threshold between Small and Large to determine which rate should apply. Third, the number of larger commercial customers on the BH Gas Utility system is much higher than the number of Large Commercial customers on the BH Gas Distribution system, so adopting one commercial rate as on the BH Gas Utility system impacts fewer customers than implementing a separate Large Commercial rate.

Q. WHY DO YOU BELIEVE THAT IT IS PREFERABLE TO IMPLEMENT THE EXISTING BH GAS DISTRIBUTION BLOCK RATE STRUCTURE?

A. As discussed in the prior section of my direct testimony, the existing block rate structure on the BH Gas Distribution system has been very effective at making the BH Gas Distribution rates more competitive with the rate structures used by the electric utilities with which they directly compete. There is a detailed discussion in Mr. Hyatt's direct

testimony regarding how the specific blocks (i.e. the consumption levels for each block) were determined.

A. Cost-based Rates

Q. HAVE YOU PREPARED RATE ANALYSES BASED ONLY ON THE RESULTS OF THE CCOSS?

A. Yes. For demonstration purposes, I have prepared analyses showing purely cost-based jurisdictional rates using the results of the CCOSS. These are not the jurisdictional rates proposed by BH Nebraska Gas in this matter; they are being provided for comparison to the jurisdictional rates proposed by BH Nebraska Gas based upon all the guidelines identified at the beginning of this section of my direct testimony that I discuss later in my direct testimony.

Q. WHERE DO YOU SHOW THE COST-BASED RATES?

A. As discussed earlier in my testimony regarding the CCOSS, Application Exhibit No. 1, Section 4, Exhibit B, Table 5 shows the calculation of the unit costs of service for the jurisdictional customer classes. These unit costs of service are summarized on Lines 23 through 28. In Exhibit No. TJS-7, I summarize the various components of customer related costs on Lines 1 through 7. The cost-based jurisdictional rates are shown on Lines 9 through 16 of Exhibit No. TJS-7. The difference between the jurisdictional customer charges shown on Line 10 and the costs on Lines 1 through 7 is primarily due to rounding the customer

charges to the nearest $0.50. The cost-based volumetric rates are shown on Lines 12 through 16.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE COST-BASED RESIDENTIAL AND COMMERCIAL CUSTOMER CHARGES?

A. The cost-based customer charges shown in Exhibit No. TJS-7 are set equal to the customer-related costs indicated in the CCOSS model as shown in Application Exhibit No. 1, Section 4, Exhibit B, Table 5 rounded to the nearest $0.50. The customer-related costs by customer class are summarized in Table TJS-2 below.

Table TJS-5 - Customer-Related Costs

Customer Class	Total Customer-Related Cost
	$/bill
Residential	24.42
Commercial	53.67

Based on these levels of customer-related costs, I set the cost-based customer charges as follows:

- Residential - $24.50 per month
- Commercial - $54.00 per month

In my view, these are the highest customer charges that should be set based on the CCOSS.

Even though fixed costs also include costs that I have classified as demand or capacity related costs (shown on Lines 25 and 26 of Table 5 of Application Exhibit No. 1,

Section 4, Schedule B, Table 5), I do not consider it appropriate to include these costs in a single customer charge applied to the entire class of service. These costs are related to the size of the customer which directly impacts the demand put on the system by the customer and thus the rate design should differentiate customer size (usage) in recovering these costs. These costs could be used to develop tiered customer charges (similar to what was discussed previously regarding some of the electric utility rate structures) or a demand charge. Since I am not proposing either tiered customer charges or demand charges, it is most appropriate that the demand related costs be recovered through the volumetric rate.

Q. HOW DID YOU DETERMINE THE COST-BASED VOLUMETRIC RATES FOR THE RESIDENTIAL AND COMMERCIAL CUSTOMERS?

A. The revenues from the cost-based volumetric rates for each class are equal to the total cost of service (revenue requirement) for each class less the revenues derived from the customer charges discussed above. Since the resulting volumetric rate is lower than the last block of the current BH Gas Distribution rates, I made no differentiation between the pricing of the two blocks under the cost based volumetric rates. The resulting cost-based volumetric rates are shown on Lines 13 and 16 of Exhibit No. TJS-7.

Q. HAS THE COMPANY PREPARED ANALYSES SHOWING THE REVENUES BY CLASS IF RATES WERE BASED ON THESE COST-BASED RATES?

A. Yes. There are two analyses. The first analysis showing the revenue proof is contained in Mr. Hyatt's Exhibit No. DNH-7. The derivation of class revenues based on cost-based rates is shown on Lines 22-49 of Exhibit No. DNH-7. The revenues under cost-based rates are compared to the revenues under existing rates on Lines 45-49. In addition, I sponsor Application Exhibit No. 1, Section 1, Schedule B2 which compares typical summer and

winter bills using the cost-based rates to the existing BH Gas Distribution and BH Gas Utility rates including the existing riders the largest of which is the System Safety Integrity Rider ("SSIR") on the BH Gas Distribution system.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE TYPICAL BILLS SHOWN IN APPLICATION EXHIBIT NO. 1, SECTION 1, SCHEDULE B2.

A. The typical bills for the residential customers on both the BH Gas Distribution and BH Gas Utility systems are based on the average test year summer and winter usage for the residential customer class. This presentation thus provides a comparison of what would be considered low-use and high-use bills. Generally speaking, virtually all residential customers are low-use customers during the summer months. The higher use occurs when these customers use natural gas for space heating during the winter months. Residential customers who are low use during the winter months are most likely not using natural gas as their primary space heating source.

Similarly, the typical bills for the commercial customers on both the BH Gas Distribution and BH Gas Utility systems are based on the average test year summer and winter usage for the commercial customer class. I have also added a typical bill comparison for what would be considered large commercial customers on both the BH Gas Distribution and BH Gas Utility systems based on the average test year summer and winter usage for the current BH Gas Distribution customers. Even though there is not a separate rate for large commercial customers on the BH Gas Utility system, I have provided a comparison of rate impacts on the larger BH Gas Utility system commercial customers for comparative purposes. The current rates for Commercial and Large Commercial customers on the BH Gas Utility system are the same.

Lines 1 through 29 of Application Exhibit No. 1, Section 1, Schedule B2 show the calculation of typical summer and winter bills under the current rates including all current riders for typical residential, commercial, and large commercial customers. Lines 30 through 45 show the calculation of typical summer and winter bills for the same consumption levels and customer classes as used under existing rates. A comparison of the total bills under existing rates to cost based rates is shown on Lines 44 and 45.

Q. PLEASE SUMMARIZE WHAT WOULD BE THE OVERALL IMPACT BY JURISDICTIONAL CLASS OF COST-BASED RATES.

A. These cost-based rates, by definition, result in all jurisdictional classes having a rate of return equal to the 7.06 percent requested by the Company. The revenue impact of these rates is shown on Line 49 of Exhibit No. DNH-7 and are summarized below in Table TJS-6. Within the rounding of the rate design, these increases are equal to the revenue deficiencies shown in Application Exhibit No. 1, Section 4, Exhibit B, Table 1, Lines 6 and 7.

Table TJS-6 - Class Revenue Impact of Cost-Base Rates

Customer Class	Revenue Increase (Decrease)	Percent Change
Residential	$13,689,802	8.6%
Commercial	$3,602,708	4.2%
Total	$17,292,510	7.1%

Q. ARE YOU RECOMMENDING BH NEBRASKA GAS IMPLEMENT FULLY COST-BASED RATES IN THIS PROCEEDING?

A. No. As discussed at the beginning of this section of my direct testimony, there are other considerations that should be reflected in addition to designing rates as nearly as practical

to the cost-based rates. However, the cost-based rates discussed above achieve the first four of the guidelines listed at the beginning of this section. The jurisdictional rates I am recommending and BH Nebraska Gas is proposing are designed meet all of the guidelines I established earlier.

B. Proposed Rates

Q. PLEASE SUMMARIZE THE SPECIFIC RATES YOU ARE RECOMMENDING.

A. As indicated in my CCOSS results summarized in Application Exhibit No. 1, Section 4, Exhibit B, Table 1, Lines 6-7, the overall revenue deficiency is $17.3 million which results in an overall increase of 7.1 percent. The specific rate design recommendations I made to achieve this and the other guidelines listed earlier in my direct testimony are as follows:

1. Set the Residential customer charge at $15.45 per month and the Commercial customer charge at $31.10 per month.
2. Set the second tier (block) of the volumetric rate for both the Residential and Commercial rates at $0.15000 per therm.
3. Set the first tier (block) of the volumetric rate for both the Residential and Commercial rates at $0.59960 per therm.

These rates are summarized on Lines 18 through 25 of Exhibit No. TJS-7.

Q. PLEASE DISCUSS THE SPECIFIC STEPS YOU TOOK TO ARRIVE AT THE RESIDENTIAL CUSTOMER CHARGE.

A. My first consideration in the design of rates was the appropriate level for the Residential customer charge. The current BH Gas Utility customer charge is $13.50 per month. In addition, as shown in Application Exhibit No. 1, Section 1, Schedule B2, the current rates paid by BH Gas Utility customers also include $0.65 per month associated with various

riders, so the total effective customer charge is $14.15 per month. The existing BH Gas Distribution customer charge is $14.70 per month and includes an additional $4.09 per month associated with various riders (the largest being $3.65 per month associated with the SSIR), so the total effective customer charge is $18.79 per month. Increasing the existing BH Gas Utility residential customer charge to a level equal to the existing BH Gas Distribution customer charge or even to the level justified by the CCOSS discussed earlier would be disruptive, particularly when combined with establishing a block rate structure, and specifically during the summer months of low usage for the BH Gas Utility residential customers. Therefore, in designing the residential customer charge, I focused on mitigating the impact on these customers. The $15.45 per month proposed customer charge achieves the goal of mitigating the impact on the BH Gas Utility customers.

Q. PLEASE COMMENT FURTHER ON THE RELATIVE LEVELS OF THE EXISTING BH GAS UTILITY AND BH GAS DISTRIBUTION CUSTOMER CHARGES INCLUDING THE EXISTING RIDERS.

A. It should be noted that the customer charge mitigation discussed above is primarily needed for two reasons. First, it has been longer since the last BH Gas Utility rate case (test year ended July 31, 2009 versus March 31, 2011, for BH Gas Distribution), thus the lower existing base customer charge on the BH Gas Utility system. Second, and more importantly, the BH Gas Distribution customers have essentially been receiving gradual rate increases to the customer charge since the last BH Gas Distribution rate case due to the SSIR. This gradualism resulting from the SSIR can both reduce the frequency of rate filings and reduce the net impact of rate increases when rate reviews are filed since a portion of the costs included in the rate review are already being reflected in the overall

rate customers with an SSIR are paying. On the other hand, the BH Gas Utility customers have not been paying for similar investments that have been required since its last rate case over 10 years ago, thus the impact of a rate change will necessarily be greater since there has not been the gradual increase in the rates the customers have been paying since the last rate case. Therefore, in my view, it is more reasonable to establish a lower customer charge than would otherwise be warranted in order to gradually increase the customer charge paid by the legacy BH Gas Utility customers. If the Commission approves the Company's proposed system-wide SSIR, the effective customer charge (approved customer charge plus riders including the SSIR) will be increased gradually over time to a level closer to customer related cost and to the current level paid by legacy BH Gas Distribution customers (which is more reflective of customer related costs).

Q. AFTER DETERMINING THE RESIDENTIAL CUSTOMER CHARGE, WHAT WAS THE NEXT STEP IN DESIGNING THE RATES YOU ARE PROPOSING?

A. My second consideration which was equally important as the Residential customer charge was developing the appropriate pricing for the proposed second tier (block) volumetric rates. The current BH Gas Distribution second tier (block) rate is $0.13380 per therm for both the residential and commercial rates. Due to the magnitude of the overall increase in the revenue requirement, and the fact that the competing electric utilities have slightly increased their winter last block rates, I determined that some increase to the existing second block was warranted. This is tempered somewhat due to the fact that the Nebraska electric utilities have implemented rates that directly target commercial heat load.

At the time of BH Gas Distribution's last rate case, the last winter block of NPPD's residential rate was 5.85 cents per kWh. The current last winter block is 6.22 cents per kWh

or 6.3 percent higher. At the time of the last BH Gas Utility rate case, the last winter block of OPPD's residential rate was 4.24 cents per kWh. The current last winter block is 5.27 cents per kWh, or 24.3 percent higher. At the time of the last BH Gas Utility rate case, the last block of LES's winter rate, was 4.57 cents per kWh and is now 5.48 cents per kWh, or 19.9 percent higher. On average, the increase of these three utilities has been 16.8 percent. On the commercial rates, the increases for NPPD, OPPD, and LES have been negative 3.8 percent (7.33 cents per kWh currently versus 7.62 cents/kWh in the last BH Gas Distribution rate case), positive 17 percent (5.24 cents per kWh currently versus 4.48 cents per kWh), and positive 17.0 percent (6.06 cents per kWh versus 5.18 cents per kWh), respectively, or 10.1 percent higher on average. These changes should also take into consideration the fact that commodity natural gas prices have declined since the Company's last round of rate cases.

Finally, I also took into consideration the impact the second tier rate would have on the pricing of the first tier. Based on all this consideration, I set the second tier for both the residential and commercial rates at $0.1500 per therm which is a 12.1 percent increase above the current rate of $0.13380 per therm.

Based on a residential customer charge of $15.45 per month and the second tier rate of $0.1500 per therm, the first tier becomes $0.59960 per therm in order to recover the residential classes' cost of service. The current BH Gas Distribution first tier rate is $0.46750 per therm for both residential and commercial customers.

Q. AFTER DETERMINING THE RESIDENTIAL RATES, HOW DID YOU DETERMINE THE COMMERCIAL RATES?

A. In order to maintain the existing residential and commercial rate relationships, I set the commercial volumetric rates equal to the residential volumetric rates, the same as they are currently. In order to recover the commercial class cost of service, a $31.10 per month customer charge is needed. This is reasonable and consistent with the results of the CCOSS which found that customer related costs for the commercial class are about 2.2 times that of the residential class. A $31.10 per month customer charge is approximately double the $15.45 per month residential customer charge.

Q. PLEASE SUMMARIZE HOW THESE PROPOSED RATES MEET ALL OF THE GUIDELINES YOU ESTABLISHED AT THE BEGINNING OF THIS SECTION OF YOUR TESTIMONY.

A. There are seven guidelines established at the beginning of this section of my testimony and each of them are met as follows:

1. As shown in Exhibit No. DNH-7, Line 77, the proposed rates result in an overall increase of $17.3 million.
2. The rates shown in Exhibit No. TJS-7 are consolidated jurisdictional rates that apply to both the BH Gas Distribution and BH Gas Utility.
3. The proposed class increases as shown in Application Exhibit No. 1, Section 4, Schedule B, Table 1, Line 8 (which tie to the numbers shown in Exhibit No. DNH-7, Line 77) are equal to, within the rounding of the rate design, the difference between existing class revenues and class cost of service as shown in Application Exhibit No. 1, Section 4, Schedule B, Table 1, Line 6 (i.e. revenue deficiency).

4. As discussed above, the last block of the proposed rate, $0.1500 per therm, was specifically design based on consideration of the last block winter rates offered by the electric utilities with which the Company directly competes.

5. While the proposed customer charges are significantly below cost of service, they do move in the direction of customer related costs. If the Company's proposed SSIR is approved, gradual increases in the fixed part of the bill (i.e. the customer charges) will occur for both the BH Gas Distribution and BH Gas Utility customers that will allow for future increases, as the SSIR is rolled into base rates, in customer charges to more closely align with cost of service.

6. The BH Gas Utility block rate mitigation guideline is essentially met in the same manner as discussed above under guideline 5. In addition, the significant increase in electric utility customer charges would have supported a higher increase in the Company's customer charges, but in order to mitigate the impact on the BH Gas Utility customers moving to a block rate structure, smaller customer charge increases are more reasonable.

7. The proposed block rates for residential and commercial customers are equal as they currently are under the existing BH Gas Distribution rates. In addition, the differential between the proposed Residential and Commercial customer charges is approximately equal to the differential in cost of service.

Q. HAS THE COMPANY PREPARED ANALYSES SHOWING THE REVENUES BY CLASS IF RATES WERE BASED ON THESE COST-BASED RATES?

A. Yes. There are two analyses. The first analysis showing the revenue proof is contained in Mr. Hyatt's Exhibit No. DNH-7. The derivation of class revenues based on proposed rates

is shown on Lines 50-77 of Exhibit No. DNH-7. The revenues under proposed rates are compared to the revenues under existing rates on Lines 73-77. In addition, I sponsor Application Exhibit No. 1, Section 1, Schedule B2 which compares typical summer and winter bills using the proposed rates to the existing BH Gas Distribution and BH Gas Utility rates including the existing riders, the largest of which is the SSIR on the BH Gas Distribution system.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE TYPICAL BILLS SHOWN IN APPLICATION EXHIBIT NO. 1, SECTION 1, SCHEDULE B2.

A. The typical bills for the residential customers on both the BH Gas Distribution and BH Gas Utility systems are based on the same typical summer and winter usage levels used in the comparison of cost-based rates to existing rates I discussed earlier in my testimony.

Lines 1 through 29 of Application Exhibit No. 1, Section 1, Schedule B2 show the calculation of typical summer and winter bills under the current rates including all current riders for typical residential, commercial, and large commercial customers. Lines 46 through 61 show the calculation of typical summer and winter bills under proposed rates for the same consumption levels and customer classes as used under existing rates. A comparison of the total bills under existing rates to proposed rates is shown on Lines 60 and 61.

As shown on Lines 60 and 61, the BH Gas Utility residential typical bills for both summer and winter show increase and the increase for the BH Gas Distribution winter bills is approximately equal to the decrease for the summer bills. As discussed earlier, the impact on BH Gas Distribution customers is lower than the BH Gas Utility Customers primarily due to the fact that the BH Gas Distribution current customer charge is higher than the BH

Gas Utility customer charge. In addition, BH Gas Distribution customers' rates include an SSIR. Effectively, the BH Gas Distribution customers have seen gradual increases since their last rate case, whereas the BH Gas Utility rates were last changed over 10 years ago. The comparisons for small commercial customers are similar to those for residential customers.

The large commercial customers on the BH Gas Utility system will see a small reduction in their bills. Smaller use (summer bills) see an increase due to the implementation of block rates, but winter bills decline due to the fact that the proposed second block commercial rate is lower than the current BH Gas Utility flat rate. As mentioned in the section regarding electric rates, the electric utilities have been specifically targeting commercial heat load, so a small decrease in winter bills will help the Company compete with these electric rates. The large commercial customers on the BH Gas Distribution system see higher decreases in their typical bills, primarily due to the fact the current SSIR for the BH Gas Distribution Large Commercial customers is relatively high (almost as much as the customer charge).

Q. PLEASE SUMMARIZE THE OVERALL IMPACT BY CLASS OF THE PROPOSED RATES.

A. The overall impact is shown in Application Exhibit No. 1, Section 4, Exhibit B, Table 1, Lines 8-13 and summarized below in Table TJS-7.

Table TJS-7- Class Revenue Impact and Rate of Return Under Proposed Rates[5]

Customer Class	Revenue Increase (Decrease)	Percent Change	Rate of Return Under Proposed Rates
Residential	$13,688,384	8.6%	7.06%
Commercial	$3,607,756	4.2%	7.06%
Total	$17,296,140	7.1%	7.06%

Q. WHAT JURISDICTIONAL RATES ARE YOU RECOMMENDING BH NEBRASKA GAS IMPLEMENT?

A. I am recommending that BH Nebraska Gas implement the proposed jurisdictional rates shown on Lines 18 through 25 of Exhibit No. TJS-7.

C. <u>Alternate Rate Design</u>

Q. WHY ARE YOU PRESENTING AN ALTERNATE RATE DESIGN?

A. If the Commission determines that it would rather implement a flat volumetric rate for the Company's residential and commercial rates, similar to the current rate structure on BH Gas Utility, I am recommending that such a rate design have higher customer charges than the rates I am recommending above. There are two rationales for this. First, as discussed earlier in my direct testimony, the electric utilities in Nebraska have generally increased the fixed component of their rates by substantial amounts since the last BH Gas Distribution and BH Gas Utility rate cases. This has allowed the electric utilities to price their volumetric rates, and specifically the last winter blocks of these rates, at lower levels. Second, as shown by the CCOSS, the customer related costs for BH Nebraska Gas are

[5] The differences between the revenue increase produced by the proposed rates and the calculated revenue deficiency (existing revenues minus class cost of service) are due to rounding the rates to significant digits.

significantly higher than the current customer charges. As discussed above, I am proposing to mitigate the impact of moving the current BH Gas Utility block rates by proposing a lower residential customer charge. If the Commission chooses not to implement a system-wide block rate structure, this rationale to mitigate the residential customer charge is no longer relevant.

Q. IF THE COMMISSION DOES NOT WISH TO IMPLEMENT BLOCK RATES ON A SYSTEMWIDE BASIS, WHAT RATES DO YOU RECOMMEND?

A. If the Commission does not want to implement block rates on a statewide basis, I am recommending that the Commission implement the rates shown on Lines 27-29 of Exhibit No. TJS-7. With the exception of block rates guidelines, these rates are based on the following guidelines that are the same as those used under proposed rates:

1. The overall increase in jurisdictional rates should total approximately $17.3 million.
2. The separate jurisdictional rates currently in place for BH Gas Distribution and BH Gas Utility should be consolidated into one set of system-wide rates as discussed in Mr. Amdor's direct testimony.
3. The rates should be designed as close as practical to align with each classes' cost of service.
4. Rates should be designed to reflect the competition faced by the Company from local municipal electric utilities.
5. The customer charges should move in the direction of reflecting customer related costs.

The specific alternate rates shown in Exhibit No. TJS-7, are based on a Residential customer charge of $22.81 per month and a Commercial customer charge of $43.65 per month. Both customer charges are below the customer related costs summarized on Lines 1-7 of Exhibit No. TJS-7. These are the customer charges that result by setting the volumetric rates for the Residential and Commercial rates equal to the proposed last block rate of $0.1500 per therm. The revenue proof for these rates is shown in Exhibit No DNH-7, Lines 78-101 and the typical bills are shown in Application Exhibit No. 1, Section 1, Schedule B2, Lines 62-73.

Q. ARE YOU RECOMMENDING THE ALTERNATE RATE DESIGN?

A. No. I am recommending the block rate structure discussed in the prior section of my testimony. However, if the Commission determines that it would rather implement a flat volumetric rate for the Company's residential and commercial rates, similar to the current rate structure on BH Gas Utility, then the alternate rates discussed in this section would be the appropriate rate design and rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.